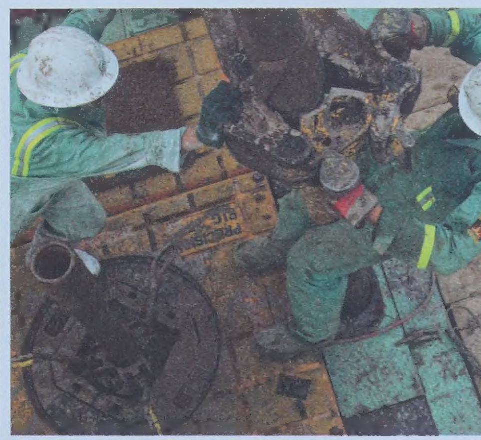
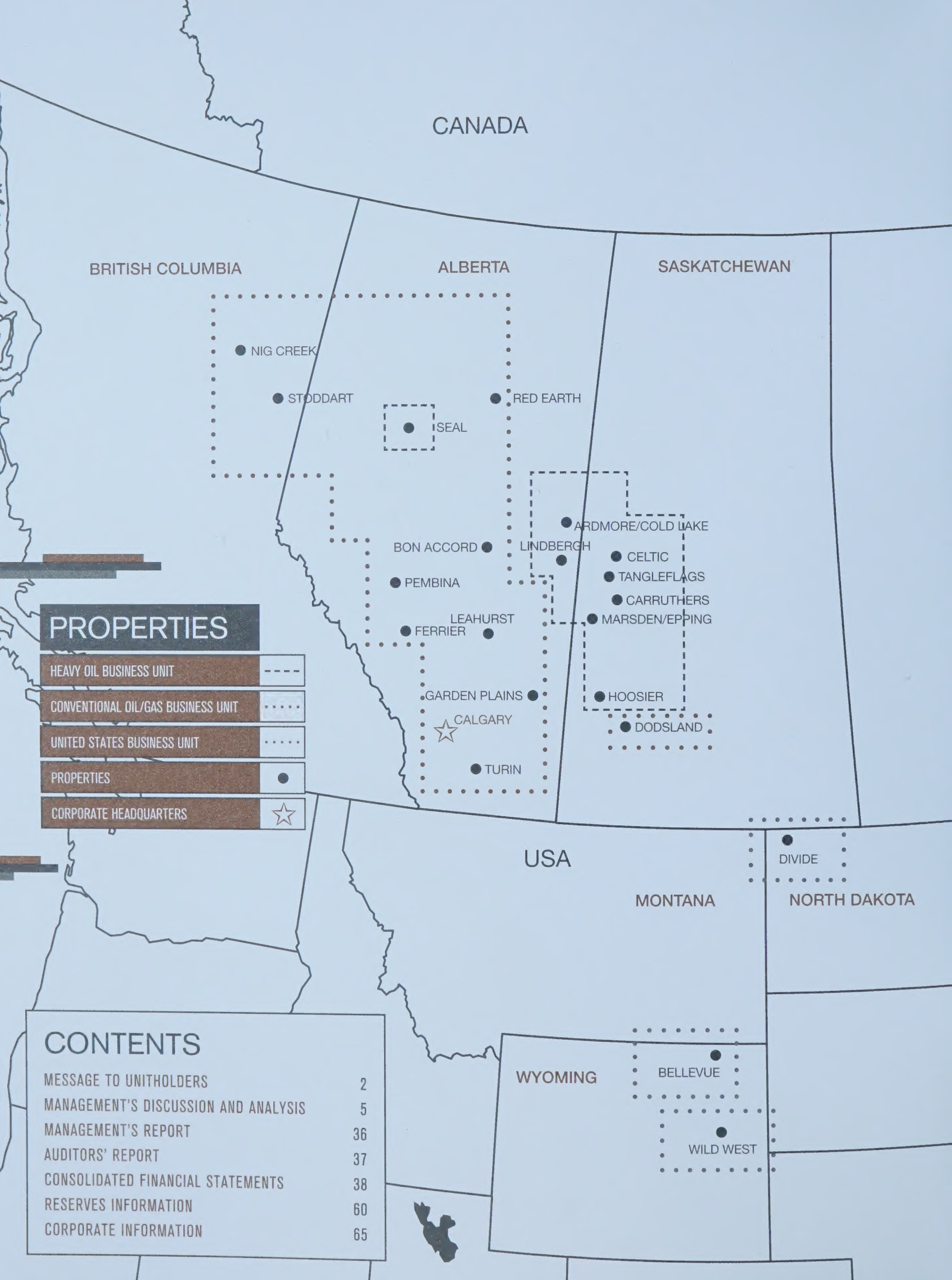
BAYTEX

ENERGY TRUST



2008

ANNUAL REPORT


CANADA
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
NIG CREEK
STODDART
RED EARTH
SEAL
ARDMORE/COLD LAKE
BON ACCORD
LINDBERGH
CELTIC
PEMBINA
TANGLEFLAGS
CARRUTHERS
LEAHURST
MARSDEN/EPPING
FERRIER
GARDEN PLAINS
HOOSIER
CALGARY
DODSLAND
TURIN
USA
DIVIDE
MONTANA
NORTH DAKOTA
WYOMING
BELLEVUE
WILD WEST
PROPERTIES
HEAVY OIL BUSINESS UNIT
CONVENTIONAL OIL/GAS BUSINESS UNIT
UNITED STATES BUSINESS UNIT
PROPERTIES
CORPORATE HEADQUARTERS

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HIGHLIGHTS

Year ended December 31	2008	2007	% change
Financial *(thousands of Canadian dollars, except per unit amounts)*			
Petroleum and natural gas sales	1,159,718	745,885	56
Cash flow from operations[1]	433,823	286,030	52
Per unit – basic	4.73	3.57	33
– diluted	4.51	3.34	35
Cash distributions	197,026	145,927	35
Per unit	2.64	2.16	22
Net income	259,894	132,860	96
Per unit – basic	2.83	1.66	70
– diluted	2.74	1.60	71
Capital expenditures			
Exploration and Development	185,083	148,719	25
Acquisitions *(net)*	265,099	245,427	8
Total Capital Expenditures	450,182	394,146	14
Total monetary debt[2]	533,018	444,065	20
Trust units outstanding at December 31 *(thousands)*[3]	97,685	87,169	12
Operating			
Production			
Light oil and NGL *(bbl/d)*	7,575	5,483	38
Heavy oil *(bbl/d)*	23,530	22,092	7
Total oil *(bbl/d)*	31,105	27,575	13
Natural gas *(MMcf/d)*	54.8	51.9	6
Oil equivalent *(boe/d)*[4]	40,239	36,222	11
Reserves, proved plus probable[5]			
Oil and NGL *(Mbbl)*	157,438	143,266	10
Natural gas *(Bcf)*	178.2	148.9	20
Oil equivalent *(Mboe)*	187,139	168,076	11
Reserve life index *(years, proved plus probable)*	12.8	12.3	4

(1) *Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items (see reconciliation under MD&A). The Trust's cash flow from operations may not be comparable to other issuers. The Trust considers cash flow from operations a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.*

(2) *Total monetary debt is a non-GAAP term and is defined in note 18 to the audited consolidated financial statements.*

(3) *Number of trust units outstanding at December 31, 2007 includes the conversion of exchangeable shares at the exchange ratio in effect on such date.*

(4) *Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

(5) *Reserves information as at December 31, 2008 and 2007 is prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101").*

This report contains forward-looking information and statements relating to: our ability to grow through exploration and development activities complimented by strategic acquisitions; our heavy oil resource play at Seal, including our assessment of the viability and economics of cyclic steam stimulation recovery, the efficiency of cyclic steam stimulation relative to other methods of thermal development and the timing for completion of a commercial-scale cyclic steam stimulation project; the production and reserves potential of our light oil resources plays in North Dakota and Saskatchewan; operating and transportation expenses for 2009; our liquidity and financial capacity; our exploration and development capital program for 2009; the timing and amount of deferred acquisition payments for the North Dakota acquisition; our production levels for 2009; our ability to fund cash distributions and our capital program from cash flow; oil prices and differentials between light, medium and heavy oil prices; the demand for and supply of crude oil; and the ability of our heavy oil projects to generate rates of return in excess of our cost of capital. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

MESSAGE TO UNITHOLDERS

We are please to report our 2008 results to our unitholders. In 2008, we achieved record levels of production, net income and cash flow. Operationally, we advanced several key projects that should provide reliable and diversified growth in coming years. We also recorded another year of capital efficiencies that again place Baytex near the top in our sector of the oil and gas industry. Finally, 2008 was a year that required flexibility in financial management to navigate the sudden economic crisis, and we responded by taking the prudent steps required to ensure Baytex's ongoing financial success.

Operations Review

Our capital program during 2008 was the largest in our history, in both aggregate terms and also for the individual components of exploration and development capital expenditures ("E&D CAPEX") and acquisition CAPEX. Spending for exploration and development CAPEX totaled $185 million, with the majority directed toward heavy oil projects. Development of our Lloydminster-area cold heavy oil properties, through both new drilling and recompletion of existing wells, maintained production rates from that key region. At Seal in the Peace River Oil Sands, we drilled 19 new cold horizontal producers, continuing our record of 100% drilling success and nearly doubling production from this important growth property to 4,500 bbl/d by the year-end. All told, Baytex participated in 152 wells on our heavy oil, light oil and natural gas properties, generating a 95% success rate.

Baytex reached another milestone that we believe will prove important for our long-term growth. At Seal, we successfully tested the application of cyclic steam stimulation ("CSS") in a well that had previously been a cold producer. The results of the test significantly exceeded our expectations, with initial rates following steam injection exceeding 900 bbl/d. More importantly, as of year-end, the test generated an impressive incremental steam-oil ratio ("SOR") of 1.5 barrels of steam per barrel of incremental oil. This SOR is far lower than the average for projects in western Canada, and suggests very high thermal efficiencies and the potential for very strong thermal operating economics. In our view, in addition to high thermal efficiency, CSS offers lower cost levels and less performance risk than alternative methods of thermal development such as Steam Assisted Gravity Drainage ("SAGD"). We were also pleased that Seal's thermal potential was validated by our independent reserve engineers, who assigned our first booking of probable reserves for CSS development in this year's reserve report. Based on our successful pilot, we are conducting the remaining design activities and reservoir modeling to install a permanent steam project, with start-up targeted for 2011.

Baytex has a reputation of being a heavy oil company. It is a reputation we deserve, and one of which we are quite proud. Nonetheless, we have quietly and steadily assembled an enviable suite of light oil projects and have nearly doubled our light oil production over the past three years. In 2008, acquisition CAPEX of $265 million was directed primarily to two major light oil and gas acquisitions. Through the acquisition of Burmis Energy completed in June 2008, we acquired approximately 3,800 boe/d with a purchase price of $180 million in Baytex units and assumed debt. The Burmis acquisition was accretive to both production and cash flow per unit, resulted in operating efficiencies in the Pembina area and provided a large set of light oil and natural gas drilling opportunities.

In November, we announced the acquisition of a significant amount of undeveloped land for $67 million in the Bakken/Three Forks play in North Dakota and the Viking play in Saskatchewan. These resource plays utilize horizontal wells with multiple hydraulic fracture stimulations to induce light oil production from low permeability reservoirs. The plays contain very large volumes of light oil resource in place and have the potential, over time, to generate significant additional increases in Baytex's light oil production and reserves. We put these new light oil resource plays in place with two purposes in mind: accretion of value to our unitholders and increased diversification of our long-term product mix and project mix. The light oil resource plays will complement development of our heavy oil resource play at Seal.

As with the Pembina/Lindbergh acquisition we made in 2007, the two acquisitions in 2008 represent a step change in our evolution as a growth-and-income oil and gas entity. Production averaged 42,287 boe/d for the second half of 2008, reflecting the full contribution of the new assets, and 40,239 boe/d for the full year. Our total capital program for 2008 amounted to $450 million. This CAPEX program resulted in Baytex growing its reserve base in both proved and probable reserve categories for the fifth consecutive year, covering our entire history as an energy trust. At year-end 2008, our proved plus probable reserves, as evaluated by Sproule Associates Limited, reached 187 million boe. This reserve total represents a 12.8 year reserve life index.

For the fifth consecutive year, Baytex continued to record exceptional CAPEX efficiencies. Finding, development and acquisition cost ("FD&A cost") was $13.11 per proved plus probable boe (excluding future development capital but including undeveloped land purchases), resulting in a recycle ratio of 2.9. Another way to look at our capital efficiency is to consider that we replaced 119% of production through E&D CAPEX, while only reinvesting 43% of cash flow into E&D activities. Including acquisitions, we replaced 231% of our 2009 production. These results are consistent with our long-term performance in capital efficiency. Our five-year average FD&A cost of $9.57 per proved plus probable boe, recycle ratio of 2.9 and reserve replacement ratio of 224% all rank among the best in our industry.

Financial Review

We are quite proud of our operating results and CAPEX efficiencies, and it is through these measures that we seek to differentiate ourselves from our competitors. Nonetheless, we recognize that our financial results are to a large degree affected by commodity prices, which are themselves determined by general economic conditions. In 2008, the economy and commodity prices were on a roller coaster.

The average West Texas Intermediate ("WTI") oil price for 2008 was US$99.59 per barrel, an increase of 38% over the average for 2007. What the average does not illustrate is the extreme upward and downward movement over the course of the year. WTI began the year at about US$92 per barrel and moved upward to a peak of US$147 per barrel at about mid-year. After peaking at that level, oil began a precipitous slide which culminated in a WTI price of US$42 per barrel at the end of the year. The six-month price decline reversed nearly five years of commodity bull market rise in the price of oil. As WTI oil prices are denominated in US dollars, a weakening Canadian currency partially reduced the impact of the oil price decline on Canadian producers. After trading just below par for most of the first half of 2008, the Canadian currency began to decline after mid-year to around US$0.81 at the end of 2008. Natural gas prices followed a similar, if more muted, trajectory as crude oil. After beginning 2008 at about $7.35 per Mcf, AECO spot prices peaked at over $11.40 per Mcf at mid-year, before tumbling to about $6.60 per Mcf at the end of 2008.

Baytex only changed its distribution level once from inception of the trust in September 2003 through February 2008. However, the commodity price roller coaster necessitated four distribution changes from February 2008 to February 2009. As commodity prices rapidly rose in the first half of 2008, we increased our monthly distribution twice to share cash flow gains with our unitholders and to preserve our tax pool balances, with the distribution reaching $0.25 per unit in June 2008. In response to the even more rapid descent of commodity prices from their mid-year peak, we reduced distributions twice to match cash outflows to inflows and to preserve liquidity, with the monthly distribution set at $0.12 per unit in February 2009.

Operating expenses continued to increase during 2008 as our major expense categories of fuel, labour and property taxes were all significantly higher. For the year, our operating expense averaged $11.62 per boe, a 15% increase over the previous year. Operating expense for the year was also impacted by the inclusion of higher cost properties acquired during 2007 for the full year in 2008. Operating expenses are expected to respond favorably to a weaker market for oilfield services and lower fuel prices in 2009. Transportation expense increased by 23% to $2.83 per boe due to higher fuel prices and higher production levels at Seal, which requires long-haul trucking. Like operating expense, transportation expense is expected to respond in 2009 to lower fuel prices. General and administrative ("G&A") expenses increased 13% to $2.00 per boe, reflecting higher costs for labour in Calgary and the costs of expanding our Denver office. We do not capitalize any G&A costs, and our G&A expense has consistently been below sector averages.

Cash flow for 2008 was a record $434 million, an increase of 52% from the previous record set in 2007. This 2008 cash flow level is net of $60 million of realized hedging losses on WTI futures contracts. Cash flow varied considerably during the year, reaching a peak of $147 million in the third quarter and a low of $60 million in the fourth quarter. Net income for 2008, including unrealized mark-to-market gains on hedging contracts for 2009, was a record $260 million, nearly double net income for 2007.

Cash distributions for 2008 were $197 million, bringing our cumulative cash distributions to unitholders since trust inception to $747 million. Payout ratio for 2008 averaged 45% net of our Distribution Reinvestment Plan ("DRIP") and 56% before DRIP.

Total monetary debt at year-end was $532 million. This debt level corresponds to 1.2 times cash flow for all of 2008, and 2.2 times annualized cash flow for the fourth quarter of 2008. Approximately 40% of our year-end debt was represented by our US dollar-denominated senior subordinated notes which mature in July 2010. Most of the remainder of our debt represents drawings on our reserve-backed revolving credit facility, which is provided by a

syndicate of nine banks from Canada, the US and Europe. At year-end, our undrawn credit facilities were in excess of $180 million, providing a significant level of liquidity to navigate the current financial environment.

Outlook

The industry and economic environment we are faced with today is very different than it was only a few months ago. It now appears that this may be the deepest recession in the post-war era. Light oil prices, as measured by WTI, have fallen from their peak of US$147 per barrel in mid-2008 to a low of US$34 during the first quarter of 2009. This decline was more rapid and more severe than almost anyone predicted.

For these reasons, we have taken the unpleasant but necessary steps to keep our cash outlays in line with our cash inflow by reducing our distribution twice and by reducing our 2009 CAPEX program from the level we originally announced. Our guiding philosophy in the trust era has always been one of sustainability. These reductions in distributions and reinvestment are consistent with maintaining a sustainable oil and gas entity. While we have reduced our overall cash outlays, we are not reducing our capability for long-term success as a growth-and-income oil and gas entity. We continue delineation and development of our land base at Seal, heavy oil drilling in Lloydminster, selective light oil and gas drilling and technical advancement of our light oil resource plays.

Our currently planned capital budget for 2009 is $150 million for E&D activities and $10 million for deferred acquisition payments related to our Bakken/Three Forks land acquisition which we made in 2008, resulting in a total CAPEX budget of $160 million. This capital budget has been reduced from our originally-announced level of $176 million. Our current capital budget is designed to maintain our production at 40,000 boe/d, which is approximately the same as the production level we averaged during 2008. Based on the commodity futures forward curve which exists as of this writing, we are projecting that cash flow in 2009 will be sufficient to fully fund our capital spending and expected cash distributions at our current monthly distribution level of $0.12 per unit.

We continue to be one of the most oil-weighted companies in the Canadian industry, with 77% of our production mix represented by heavy and light oil. Our commodity market view is that erosion of the world's capability to supply oil will occur surprisingly rapidly during this period of low oil prices, setting the stage for oil price recovery, perhaps even before resumption of significant oil demand growth. We believe that Baytex, with its large portfolio of oil development projects and a consistent long-term record of low development costs, is in a strong position to benefit when the oil price recovery occurs. In the meantime, we will take the prudent steps required to preserve liquidity as long as oil prices stay at their current levels.

We are fortunate to be particularly weighted to heavy oil. At this writing, differentials for heavy oil have meaningfully contracted, with the differential for Lloyd blend currently trading at about 15% of WTI as compared to 34% in the fourth quarter of 2008. As a result, wellhead prices for heavy oil are at levels which provide high rates of return on our capital investment program, well in excess of our cost of capital. We would venture to say that these rates of return on our heavy oil investment portfolio are among the highest presently available in the oil and gas industry in North America.

For the first five years of our history as an income trust, from September 2003 to September 2008, we supplied our unitholders with the highest total return of any oil and gas trust, totaling 386% when reinvestment of distributions is included. Over that same period, the S&P/TSX Capped Energy Trust and TSX Composite Indices returned 171% and 84%, respectively. Since that five-year milestone, the capital markets have proved less hospitable. For 2008, our total return was −14%, as compared to −27% and −33% for the two aforementioned indices.

I want to assure you that the Board of Directors, officers and employees of Baytex will redouble their efforts on behalf of unitholders during this period of general economic challenge. It remains an honour to serve our unitholders, and we want to express our appreciation for your continued support as we move forward in executing our long-term plan.

On behalf of the Board of Directors,

Anthony Marino
President and Chief Executive Officer
March 16, 2009

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Trust for the year ended December 31, 2008. This information is provided as of March 16, 2009. In this MD&A, references to "Baytex", the "Trust", "we", "us" and "our" and similar terms refer to Baytex Energy Trust and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Trust's audited consolidated comparative financial statements for the years ended December 31, 2008 and 2007, together with accompanying notes, and Annual Information Form for the year ended December 31, 2008. These documents and additional information about the Trust are available on SEDAR at www.sedar.com.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on Generally Accepted Accounting Principles in Canada ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, asset retirement expenditures, and decrease in deferred obligations. The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income. For a reconciliation of cash flow from operations to cash flow from operating activities, see "Cash Flow from Operations, Payout Ratio and Distributions".

2008 OVERVIEW

Baytex Energy Trust is an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to a trust indenture. Baytex was established on September 2, 2003 in connection with a Plan of Arrangement of our subsidiary, Baytex Energy Ltd. (the "Company"). Through our subsidiaries, we are actively engaged in the exploration, development and production of oil, natural gas and natural gas liquids in Canada in the provinces of British Columbia, Alberta and Saskatchewan and in the United States in North Dakota and Wyoming.

Our business objective has been to maintain production levels through investing approximately half of our internally generated cash flow while distributing the balance of our cash flow to holders of our trust units. Over our life, we have grown our reserve base and added to production levels through exploration and development activities complimented by strategic acquisitions.

During 2008, the Trust executed a successful capital program (excluding acquisitions) resulting in the replacement of 119% of production (on a proved plus probable basis) by spending 43% of cash flow from operations. When acquisitions are included, the Trust replaced 233% of production by spending 63% of cash flow.

As at December 31 2008, we had a reserve base of 187 million (gross) boe on a proved plus probable basis. During the year ended December 31, 2008, our production averaged 40,239 boe/d primarily in Canada, with minor amounts of production contributed from our U.S. operations.

On June 4, 2008, we acquired all of the issued and outstanding shares of Burmis Energy Inc. ("Burmis") on the basis of 0.1525 of a Baytex trust unit for each Burmis common share. Approximately 6.38 million Baytex trust units were issued to acquire Burmis. Pursuant to this transaction, we acquired multi-zone, liquids-rich natural gas and light oil properties located in west central Alberta and approximately 110,300 net acres of undeveloped land. Production from the Burmis properties averaged 3,791 boe/d during the first quarter of 2008.

During the third quarter of 2008, we reached agreement to acquire a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in North Dakota from a private company. Upon making all deferred payments associated with the transaction, we will have acquired a 37.5% interest in 263,000 gross acres (approximately 98,625 net acres). At the time of the acquisition, 94% of the lands were undeveloped. In addition, we acquired approximately 300 boe/d (95% oil) of company interest production. The seller retained the remaining 62.5% interest in the project lands and production.

PROPERTY REVIEW

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2008, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Conventional Oil and Gas and U.S. business units. Each business unit has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these business units, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Baytex invested approximately $82 million in land over the past two years targeting three light oil resource plays. These plays include the Bakken/Three Forks in the Williston Basin of North Dakota, the Viking in southwestern Saskatchewan and eastern Alberta and a Mowry Shale exploratory play in the Powder River Basin of eastern Wyoming. These light oil resources plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

Heavy Oil Business Unit

The Heavy Oil business unit accounts for more than 55% of current production and more than 65% of oil-equivalent reserves. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 250 bbl/d of crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2008, production in the Heavy Oil business unit averaged approximately 23,530 bbl/d of heavy oil and 6,654 Mcf/d of natural gas (24,639 Boe/d). Baytex drilled 111 (103.8 net) wells in the Heavy Oil business unit resulting in 105 (97.8 net) oil wells, 4 (4.0 net) stratigraphic test wells, and 2 (2.0 net) dry and abandoned wells, for a success rate of 98%.

The Heavy Oil business unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore and Peace River in Alberta. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Because of our large inventory of heavy oil projects, we are able to select from a wide range of investment opportunities to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's historical area of

emphasis around Lloydminster. Our net undeveloped lands in the Heavy Oil business unit totalled approximately 348,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Heavy Oil Business Unit:

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2008 was approximately 1,395 bbl/d of oil and 455 Mcf/d of natural gas (1,471 boe/d). Seven successful oil wells and no dry holes were drilled in the area during 2008. Baytex anticipates drilling four wells in this area in 2009. Due to extensive Baytex infrastructure in this area, operating expenses in 2008 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2008.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. No new wells were drilled in 2008, but 4 re-completions were conducted. Despite the absence of new well drilling, year-over-year production decline was only about 8% due mostly to strong performance of the ongoing waterflood. Average production in 2008 was approximately 2,115 bbl/d of heavy oil and 650 Mcf/d of natural gas (2,224 boe/d). Net undeveloped lands were 9,900 acres at year-end 2008.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 4,670 bbl/d of heavy oil and 1,118 Mcf/d of natural gas (4,856 boe/d) during 2008. (This production number includes very minor production in the area held prior to the Celtic acquisition). Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2009, Baytex expects to drill 10 new wells and re-complete approximately 45 existing wells. Net undeveloped lands were 8,800 acres at year-end 2008.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2008 was approximately 507 bbl/d. Baytex drilled two successful oil wells in the Cold Lake area in 2008, and we plan to drill three new wells in the area in 2009. Net undeveloped lands were 13,600 acres at year-end 2008.

Dodsland, Saskatchewan: During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 API) oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex targeted the less permeable but undeveloped areas of the play and drilled a 1,400 metre horizontal well in 2008. The horizontal well was completed with 7 fracture stimulations, applying the same multi-zone fracture technology that is used to stimulate horizontal wells in the Bakken oil play in southeast Saskatchewan and North Dakota. At year-end 2008, Baytex had leased 34,600 net acres in the play. Ultimately, up to 150 wells may be drilled on these lands.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2008 was approximately 3,380 bbl/d of oil and 831 Mcf/d of natural gas (3,518 boe/d). Twenty-three successful oil wells were drilled in this region in 2008. In addition, a significant facility expansion involving water flow-lining and conservation of the solution gas was completed. This project has reduced operating costs in the area and tied-in approximately 300 mcf/d of solution gas into the local sales network. For 2009, a further 14 wells are planned. Net undeveloped lands were 26,300 acres at year-end 2008.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in 105 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced using horizontal wells at initial rates of 150 to 250 bbl/d per well, without employing

more cost-intensive methods such as steam injection. In 2008, Baytex drilled four stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 19 horizontal production wells in 2008, bringing the total number of producing wells to 44. The average production rate during 2008 was 3,707 bbl/d of heavy oil. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase economic oil reserves beyond what is achievable with cold primary recovery. A cyclic steam pilot project was carried out on an existing horizontal producer during 2008 to validate the numerical reservoir simulation models. Due to the positive results from our steam pilot, the year-end 2008 reserve report included an assignment for thermal reserves at Seal for the first time. This reserve assignment supports our assessment that commercial cyclic steam development at Seal is economically viable. Seal area facilities were expanded in 2008 by constructing a water disposal plant and a fuel gas supply pipeline. Operating costs for primary production are forecasted to remain very low at $4 to $5/bbl and the gas pipeline ensures an adequate fuel supply for future thermal development of the property. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2009, Baytex plans to drill two additional stratigraphic test wells and 14 additional cold horizontal production wells. Net undeveloped lands were 65,000 acres at year-end 2008.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of re-completion opportunities. In 2008, the company drilled 3 wells and a further 15 wells were either re-started or re-completed to a new zone. Average production during 2008 was approximately 1,626 bbl/d of heavy oil and 915 Mcf/d of natural gas (1,779 boe/d). In 2009, Baytex plans to re-work or re-complete about 15 existing wells. Net undeveloped lands were 7,100 acres at year-end 2008.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.25% working interest. Company-interest production is approximately 800 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. Nine (1.9 net) wells were drilled in this area in 2008. Baytex expects the field operator to maintain a level of activity that would result in an approximately flat production rate. Net undeveloped lands were 11,000 acres at year-end 2008.

Conventional Oil and Gas Business Unit

Although Baytex is best known as a “heavy oil” energy trust, we also possess a growing array of light oil and natural gas properties. In addition to Baytex’s historical light oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Conventional Oil and Gas business unit produces light and medium gravity crude oil, natural gas and natural gas liquids (“NGL”) from various fields in Alberta and British Columbia. During 2008, production from this business unit averaged 48,066 Mcf/d of natural gas sales and 7,401 bbl/d of light oil and NGL (15,412 boe/d). During 2008, the Conventional business unit drilled 31 (21.4 net) wells resulting in 18 (11.9 net) gas wells, 7 (4.1 net) oil wells, 2 (1.4 net) service wells, and 4 (4.0 net) dry holes for a success rate of 87.1% (81.3% net). Our net undeveloped lands in this business unit were approximately 329,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the Conventional Oil and Gas Business Unit:

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2008, production for the area averaged approximately 2,524 Mcf/d of gas and 264 bbl/d of light oil (685 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2008, Baytex drilled two (1.75 net) oil wells in this area. At year-end 2008, Baytex had 11,500 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2008 averaged

approximately 2,209 Mcf/d of gas (368 boe/d). At year-end 2008, Baytex had 18,100 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 4,109 Mcf/d of gas and 11 bbl/d of NGL (696 boe/d) during 2008 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2008, Baytex participated in the drilling of 4 operated and 1 non-operated locations, resulting in 4 (2.9 net) producing gas wells and 1 (1.0 net) dry hole. At year-end 2008, Baytex had 11,700 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its initial position in Pembina in June 2007 and further expanded its presence in the area through the acquisition of Burmis in June 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations including the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2008, Pembina production averaged 4,062 bbl/d of light oil and NGL and 13,272 Mcf/d of gas (6,274 boe/d). Baytex participated in drilling 6 (5.0 net) operated and 2 (0.6 net) non-operated locations in 2008. Four wells (2.3 net) were drilled to test Nisku prospects, resulting in 1 (0.6 net) oil well, 1 (0.4 net) gas well and 2 (1.4 net) service wells. Four (3.3 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2008, resulting in 3 (3.0 net) gas wells and 1 (0.25 net) dry hole. The 2009 drilling program for Pembina will include up to three wells to evaluate Nisku prospects and four wells for multi-zone Cretaceous potential. During the first quarter of 2009, Baytex will be constructing a pipeline in the Pembina O'Chiese area to increase gas volumes delivered to market and improve netback prices for our Pembina production. At year-end 2008, Baytex had 32,600 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001, and significantly increased its presence with a 2004 acquisition of a private company. During 2008, production averaged approximately 5,971 Mcf/d of sales gas and 11 bbl/d of NGL (1,006 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas produced from this area is processed at two Baytex-operated gas plants. During 2008, Baytex drilled 5 (1.7 net) wells in this area, resulting in 3 (1.5 net) gas wells and 2 (0.2 net) oil wells. At year-end 2008, Baytex had 29,200 net undeveloped acres in this area.

Red Earth/Goodfish/Lafond, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2008 averaged approximately 4,058 Mcf/d of gas and 770 bbl/d of light oil and NGL (1,446 boe/d). During 2008, Baytex drilled 4 (3.1 net) wells in this area, resulting in 1 (0.5 net) oil well, 1 (0.6 net) gas well, and 2 (2.0 net) dry holes. At year-end 2008, Baytex had 28,600 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2008 averaged approximately 8,375 Mcf/d of gas and 1,392 bbl/d of oil and NGL (2,788 boe/d). Baytex drilled 3 (2.4 net) wells in 2008 resulting in 1 (1.0 net) oil well, 1 (0.4 net) gas well, and 1 (1.0 net) dry hole. During 2009, Baytex plans to drill two wells in the area. At year-end 2008, Baytex had 32,000 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2008 averaged approximately 519 bbl/d of oil and NGL and 1,383 Mcf/d of gas (750 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. During 2008,

Baytex drilled one (0.1 net) gas well in this area. At year-end 2008, Baytex had 9,600 net undeveloped acres in this area.

United States Business Unit

Through our wholly-owned subsidiary, Baytex Energy USA Ltd. ("Baytex USA"), we acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. During 2008, Baytex USA drilled and/or acquired an interest in 34 (12 net) wells and increased its acreage position to over 120,000 net acres. Net production from the United States properties averaged 188 boe/d in 2008, and 339 boe/d in December 2008.

Listed below is a brief description of the principal properties within the United States Business Unit:

Williston Basin – Bakken/Three Forks Project: This light oil resource play is located in the Divide and Burke Counties of North Dakota. Production is primarily from horizontal wells using multi-zone hydraulic fracturing in the Bakken and Three Forks formations. Both zones are accessed through a single horizontal lateral. Baytex USA has invested in approximately 251,000 (94,000 net) acres of land. In 2008, Baytex USA participated in 8 gross (3 net) wells. Baytex USA also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. This survey was 73% complete at the end of 2008. Net production from the project was approximately 341 boe/d in the fourth quarter of 2008. In 2009, Baytex USA plans to drill 6 gross (2.25 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial rates expected to be 190 boe/d or more per well and average recoveries expected to be 280 mboe/well or more.

Powder River Basin – Mowry Shale Play (Wild West): In September 2007, Baytex USA acquired its initial leasehold interest in this Mowry shale play covering approximately 15,300 (9,200 net) acres. A vertical well (Baytex USA 60% working interest) was drilled in 2008 to acquire core and ultimately serve as a microseismic monitoring well for subsequent horizontal-well fracturing. Completion of the vertical well, including hydraulic fracturing, is scheduled for the first quarter of 2009. Baytex USA views horizontal, multi-zone hydraulically-fractured wells as the most promising method to ultimately develop the Mowry, although there have been no horizontal wells drilled in the project area to-date. A horizontal well is planned to further evaluate the prospect in 2009. Ultimately, the project may include up to 60 horizontal wells.

MARKETING

Crude Oil

The year 2008 was marked by the unprecedented volatility in world oil prices. Early in the year strong worldwide oil demand growth coupled with limited spare production capacity pushed prices to all time highs. During the fourth quarter demand for oil collapsed on the back of plunging economic conditions which were exacerbated by high energy prices. Inventories swelled reflecting demand destruction and naturally prices fell steeply. The ongoing sub-prime mortgage and credit crisis created much uncertainty in the financial and commodity markets, adding to price weakness and volatility. For the most part, these financial considerations overshadowed geopolitical events in spite of the protracted conflicts in Iraq and Afghanistan and the fear of Iran's potential entry into the world's nuclear club.

Prices for New York Mercantile exchange traded West Texas Intermediate ("WTI"), the benchmark for Canadian crude oil sales, peaked at US$147.27 per barrel on July 11th and plunged to a low for the year on December 19th of US$33.87 per barrel – a staggering 77% decline from the peak. This represents the largest crude oil price drop in history. World demand for oil and products decreased to 85.8 million barrels per day (according to the International Energy Agency) from 86.0 million barrels a day in 2007. United States demand alone dropped by 0.5 million barrels a day over the year. Weather was not a significant factor in 2008 despite some refinery shut downs in the U.S. Gulf Coast which caused local refined product shortages in September due to hurricanes. Hurricane activity did not significantly affect critical U.S. Gulf Coast crude oil or natural gas production facilities.

Benchmark WTI prices averaged US$99.59 per barrel during 2008 which obscures the drastic monthly changes in the market during the fourth quarter. The price in 2008 was on average 38% higher than 2007 when the price averaged US$72.31 per barrel. The 5-year WTI average is US$67.22 per barrel.

Canadian Par crude at Edmonton averaged $102.86 per barrel in 2008 versus $76.35 per barrel in 2007, up 33% for the year. The 5-year Canadian Par average price is $74.55 per barrel.

Canadian heavy sour crude price differentials were generally much tighter this year at 23% of WTI than the previous five-year average of 33%. Again the extremes were severe in 2008 between the highs at 46% in December and the low of 14% during the summer. We believe that the December differential was anomalous due to the lag between negotiated fixed differentials in the market and the month of delivery drop in benchmark WTI prices. The December fixed differentials were negotiated in mid-November when they would have provided a 24% differential, but WTI dropped precipitously (by over US$15.00 per barrel) into the delivery month of December. We believe that Canadian heavy sour crude price differentials will remain low through 2010.

Baytex's conventional light crude oil and NGL prices averaged $88.92 before hedging, 36% higher than the $65.53 per barrel we received in 2007. For portions of 2008, the Canadian light sweet crude oil prices were depressed due to logistical challenges and competitive market pressures from new U.S. Bakken production.

Our heavy oil wellhead prices averaged $65.22 per barrel in 2008, 47% higher than the $44.28 per barrel we received in 2007 due to fundamental changes in the supply/demand balance for Canadian heavy crude oil. Several refineries completed heavy crude oil conversion projects in the markets served by Canadian heavy crude and supply growth out of the Western Canadian Sedimentary Basin was muted due to high costs and poor project delivery performance. This combination along with improved pipeline access and capacity meant that Canadian heavy crude was in good demand. Diluent premiums also decreased over the period which contributed to improved netbacks for Canadian heavy crude. As mentioned above, the market was disappointed by marginal increases in heavy crude supply at the same time much rail receipt capacity was added to bring in U.S. sourced diluent (condensate and naphtha). Further, the price of U.S. naphthas and natural gasoline was depressed due to a worldwide oversupply of waterborne naphtha-like material due to new NGL liquefaction projects. The net result was a significant decrease in Canadian diluent prices, which is a significant cost input to production of Canadian heavy crude oil blends.

In October and November of 2007, Baytex entered into physical heavy sour crude oil sales agreements with four parties. The contracts required Baytex to deliver 15,340 bbl/d of Lloydminster Blend or Western Canadian Select ("WCS") heavy crude oil blend for 2008, and 10,340 bbl/d for 2009. Prices received from these agreements average 68% of WTI in 2008 and 67% in 2009. In January 2009, we added two physical heavy sour crude oil sales agreements to contribute to the management our heavy oil pricing volatility exposure by selling 775 bbl/d of WCS heavy crude oil to counterparty at WTI minus a fixed US$10.00 per barrel and 775 bbl/d at 80% of delivery month WTI. These agreements commence April 1, 2009 and terminate August 31, 2009. The cumulative affect of these agreements significantly reduces the volatility of Baytex's cash flows from heavy crude oil sales.

WTI costless collars have been put in place for 2009 on 4,000 barrels per day at a weighted average price from US$100.00 per barrel to US$154.55 per barrel. No collars or any other hedging instruments have yet been implemented for 2010.

The market and infrastructure solutions for our Seal area remain a work-in-progress. Long-term logistical solutions are being developed for the area. Pembina Pipeline announced on August 12, 2008 that they are installing two pipelines to serve the area by mid-2011. The first pipeline will provide 100,000 bbl/d of blended heavy crude oil capacity to the Edmonton market. The second pipeline will provide 22,000 bbl/d of condensate/diluent supply to the Nipisi/Seal region for use in blending bitumen to pipeline viscosity specifications. Both lines can be expanded by 50%. This new capacity should open up existing capacity on the Rainbow Pipeline operated by Plains Marketing which also serves the region. Plains Marketing is also considering providing condensate/diluent service to the area. Baytex does not have term transportation obligations in place with either party.

Natural Gas

Natural gas prices in North America weakened in 2008 due to a significant growth in U.S. domestic natural gas supply and, later in the year, reduced demand due to a slumping economy. In 2007, natural gas prices were negatively affected in the latter half of the year as some three Bcf/d of liquefied natural gas ("LNG") was imported during the summer months into the U.S. from foreign sources. During 2008, LNG did not enter the market in significant quantities, but this was completely offset by growth of 6% or 3.3 Bcf/d in domestic U.S. gas production. The new production came from the Rockies basin and the new shale basins in Texas and Louisiana. It is expected that demand will be lost in the coming year due to low industrial and commercial demand due to a weak economy.

During the first half of 2008, high oil prices sustained natural gas prices at levels that might have been much lower in a lower alternative energy price environment. Second half gas prices were negatively impacted as the general economic environment deteriorated, and industrial demand collapsed. U.S. gas prices peaked at US$12.96 per MMBtu in July and dipped to close the year at US$6.47 per MMBtu. U.S. natural gas inventories continue to stay within the five year average. In addition to the new supply from U.S. sources, there was little in the way of any weather related disruptions as suffered during the 2005 hurricane season. U.S. gas prices represented by the NYMEX futures contract, averaged US$9.03 per MMbtu in 2008, an increase of 32% from US$6.86 per MMbtu in 2007 – all on the back of higher crude oil prices. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.15 per Mcf in 2008, up 27% from $6.44 per Mcf in 2007. The five-year averages are US$7.57 per MMBtu for the NYMEX contract, and $7.27 per Mcf for Alberta daily prices. We expect gas drilling to drop off throughout North America which, along with general improvement in the continental economy, will bring the supply/demand picture into better balance by 2010.

For 2008, Baytex had entered into several physical forward sales contracts with price collars. Baytex received an average of $7.92 per Mcf for 2008 natural gas sales compared to $6.61 per Mcf in 2007, a 7% increase. Baytex entered into one natural gas collar for calendar 2009 for a volume of 4,739 Mcf/d with a floor (put price) of $7.39 per Mcf and a ceiling (call price) of $8.39 per Mcf.

OPERATIONS

Production

The Trust's average production for fiscal 2008 was 40,239 boe/d compared to 36,222 boe/d for fiscal 2007.

For the year ended December 31, 2008, light oil and NGL production increased by 39% to 7,575 bbl/d from 5,483 bbl/d for last year. The increase primarily resulted from the inclusion of full-year results from the Pembina assets acquired in June 2007 and from the acquisition of Burmis Energy Inc. in June 2008. Heavy oil production for 2008 increased by 7% to 23,530 bbl/d, as compared to 22,092 bbl/d for 2007. The increase in heavy oil production stemmed from development activities and the inclusion of full-year production from the Lindbergh assets acquired in June 2007. Natural gas production increased by 6% to average 54.8 MMcf/d for 2008 compared to 51.9 MMcf/d for 2007 due largely to the Pembina and Burmis acquisitions in June 2007 and 2008, respectively.

	Light Oil and NGL *(bbl/d)*	Heavy Oil *(bbl/d)*	Natural Gas *(MMcf/d)*	Oil Equivalent *(boe/d)*
2008				
Heavy Oil Business Unit	–	23,530	6.7	24,639
Conventional Oil and Gas Business Unit	7,575	–	48.1	15,600
Total Production[1]	7,575	23,530	54.8	40,239
2007				
Heavy Oil Business Unit	–	22,092	7.3	23,315
Conventional Oil and Gas Business Unit	5,483	–	44.6	12,907
Total Production	5,483	22,092	51.9	36,222

(1) *Per unit calculations throughout the MD&A are based on sales volumes, which differ from production volumes due to changes in inventory balances related to heavy oil, as discussed below.*

Revenue

Petroleum and natural gas sales for 2008 increased by 55% to $1,159.7 million from $745.9 million for fiscal 2007. Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for 2008 were 300 bbl/d higher (2007 – 340 bbl/d higher) than the production for the period due to changes in inventory.

Benchmark WTI crude oil averaged US$99.59 per barrel for 2008, representing a 38% increase over the US$72.31 per barrel for 2007. The Trust's light oil and NGL price averaged $88.92 per barrel for 2008, representing a 36% increase over the 2007 price of $65.53 per barrel. The heavy oil price increased 46% to $65.22 per barrel in 2008 from $44.53 per barrel in 2007. Natural gas prices were 20% higher in 2008, averaging $7.92 per Mcf compared to $6.61 per Mcf during the previous year.

For 2008, light oil and NGL revenue increased 88% from the same period last year due to a 36% increase in wellhead prices and a 38% increase in sales volume. Revenue from heavy oil increased 56% due to a 46% increase in wellhead prices and a 7% increase in sales volume. Revenue from natural gas production increased 27% compared to 2007, as production increased 6% combined with a price increase of 20%.

During 2008, sulphur production averaged 48.9 tonnes per day with an average price of $381 per tonne. In prior years, sulphur revenue was not material for reporting purposes.

During the first quarter of 2008, Baytex received a $2.0 million payment from a company as compensation for non-performance of a drilling obligation which was reported as other income under petroleum and natural gas sales.

	2008		2007	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Oil revenue				
Light oil & NGL	**246,516**	**88.92**	131,143	65.53
Heavy oil(2)	**568,841**	**65.22**	364,581	44.53
Total oil revenue	**815,357**	**70.94**	495,724	48.65
Natural gas revenue	**158,845**	**7.92**	125,235	6.61
Total oil and gas revenue	**974,202**	**65.66**	620,959	46.53
Sulphur revenue	**6,820**		–	
Other income	**2,000**		–	
Sales of heavy oil blending diluent	**176,696**	**110.30**	124,926	82.94
Total petroleum and natural gas sales	**1,159,718**		745,885	

(1) Per-unit oil revenue is in $/bbl; per-unit natural gas revenue is in $/Mcf; and per-unit total revenue is in $/boe.
(2) Heavy oil wellhead prices are net of blending costs.

Financial Instruments

The gain on financial instruments for the year ended December 31, 2008 was $59.8 million, as compared to a loss of $34.5 million in 2007. For 2008, this is comprised of $60.1 million in realized loss and $119.9 million in unrealized gain, as compared to $3.2 million in realized loss and $31.3 million in unrealized loss in 2007.

Royalties

For the year ended December 31, 2008, royalties increased to $207.5 million from $102.8 million for last year. Royalties for 2008 include $0.9 million related to the production of sulphur. Total royalties in 2008 were 21% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% of sales for 2007. For 2008, royalties were 23% of sales for light oil, NGL and natural gas and 20% for heavy oil (excluding sales of heavy oil diluent), as compared to 19% and 15%, respectively, for the same period in 2007. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume escalate. Heavy oil royalties as a percentage of revenue were higher in the year as market prices, on average, were higher than the prices realized by Baytex under fixed differential supply agreements. Heavy oil royalties also increased in 2008 as certain oilsands projects at Seal and Cold Lake reached payout, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the year ended December 31, 2008 increased to $172.5 million from $134.7 million in 2007. Operating expenses for 2008 include $0.3 million related to the production of sulphur. Operating expenses were $11.62 per boe for 2008 as compared to $10.09 per boe for the prior year. In 2008, operating expenses were $11.68 per boe of light oil, NGL and natural gas and $11.55 per barrel of heavy oil as compared to $9.61 and $10.40, respectively, in 2007. In the case of light oil, NGL and natural gas, increased operating expense was driven primarily by increases in costs for third-party processing (including prior-period adjustments), fuel, power and labor. In the case of heavy oil, increased operating expense was due primarily to increased fluid hauling charges, and higher property taxes. Heavy oil operating expense was also negatively impacted by inclusion of higher-cost production at Lindbergh for the full year.

Transportation and Blending Expenses

Transportation and blending expenses for the year ended December 31, 2008 were $218.7 million compared to $155.8 million for 2007. Transportation expense for 2008 included $1.3 million related to the transportation of sulphur. Transportation expenses were $2.83 per boe in 2008 compared to $2.31 per boe in 2007. Transportation expenses were $0.64 per boe of light oil, NGL and natural gas and $4.22 per barrel of heavy oil in 2008, compared to $0.80 and $3.26, respectively, in 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and fuel costs which increased by over 25% from 2007 to 2008. In 2008, the blending cost was $176.7 million for the purchase of 4,377 bbl/d of condensate at $110.30 per barrel, as compared to $124.9 million for the purchase of 4,127 bbl/d at $82.94 per barrel in 2007.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of its heavy oil. The cost of diluent is effectively recovered in the sale price of a blended product.

Net Revenue

	Light Oil & NGL ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGL ($/bbl)		Natural Gas ($/Mcf)		BOE ($/boe)	
	2008	2007	2008	2007	2008	2007	2008	2007	2008	2007
Sales price[(1)]	88.92	65.53	65.22	44.53	70.94	48.65	7.92	6.61	65.66	46.53
Royalties	(22.97)	(12.99)	(12.93)	(6.68)	(15.35)	(7.91)	(1.50)	(1.17)	(13.92)	(7.70)
Operating costs	(12.38)	(10.79)	(11.55)	(10.40)	(11.75)	(10.48)	(1.85)	(1.48)	(11.60)	(10.09)
Transportation	(0.47)	(0.66)	(4.22)	(3.26)	(3.31)	(2.75)	(0.13)	(0.15)	(2.74)	(2.31)
Net revenue	53.10	41.09	36.52	24.19	40.53	27.51	4.44	3.81	37.40	26.43

(1) *Sales price is before realized loss/gain recognized on financial derivative contracts and sulphur production and is net of blending costs for heavy oil.*

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2008 were $29.6 million, compared to $23.6 million for the prior year. On a per sales unit basis, these expenses were $2.00 per boe in 2008 and $1.77 per boe in 2007. The increase is attributable to escalating costs in the labor market and additional expenses associated with a new office in Denver to manage the U.S. operations. In accordance with our full cost accounting policy, no expenses were capitalized in either 2008 or 2007.

($ thousands)	2008	2007
Gross corporate expense	37,554	32,132
Operator's recoveries	(7,950)	(8,567)
Net expenses	29,604	23,565

Unit-based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $7.8 million for the year ended December 31, 2008 compared to $8.0 million for 2007.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Interest Expense

For the year ended December 31, 2008, interest expense was $33.0 million compared to $35.2 million for last year. Interest expense was affected by a more favorable exchange rate on the U.S. dollar denominated interest expense and through lower interest on reduced bank borrowings. These factors were partially offset by accretion of the discontinued fair value hedge.

Foreign Exchange

The foreign exchange loss for the year ended December 31, 2008 was $37.7 million compared to a gain of $32.4 million in the prior year. The 2008 loss is comprised of an unrealized foreign exchange loss of $41.7 million and a realized foreign exchange gain of $4.0 million. The 2007 gain was substantially unrealized. The 2008 unrealized loss stemmed from the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 1.0120 CAD/USD at December 31, 2007. The 2007 unrealized gain was based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 0.8581 CAD/USD at December 31, 2006.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $223.9 million for the year ended December 31, 2008 compared to $189.5 million for 2007. On a sales-unit basis, the provision for the current year was $15.09 per boe compared to $14.20 per boe for 2007. The higher rate is primarily due to the acquisition of Burmis in June 2008.

Taxes

On June 22, 2007, the Federal Government's bill regarding the taxation of distributions of publicly traded income trusts beginning January 1, 2011 received Royal Assent. See "– Federal Government's Trust Tax Legislation." As a result, we recognized a future income tax recovery of $0.5 million in the second quarter of 2007 relating to unutilized tax pools which will be deductible to us after 2010. The majority of our temporary differences reside in a consolidated subsidiary which is not subject to the distribution tax, and is therefore not impacted by this legislative change.

Current tax expense for the year ended December 31, 2008 is comprised of $10.2 million of Saskatchewan capital tax and resource surcharge. The 2007 current tax expense included $7.2 million of Saskatchewan capital tax and resource surcharge, and a recovery of $0.5 million relating to a prior period.

The fiscal 2008 provision for future taxes was an expense of $15.4 million compared to a recovery of $49.4 million for the prior year. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 – $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 – $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 – $153.9 million). The increase from the prior year is due to future tax liability recognized on the Burmis acquisition of $37.9 million and current year provision of $25.4 million attributable to the unrecognized gain on financial instruments of $119.9 million.

As a result of the Pembina/Lindbergh acquisition in 2007, Baytex recognized a future tax liability of $74.5 million arising from the difference between the $64.0 million in tax pools acquired and the value assigned to the assets.

Federal Tax Pools

($ thousands)	2008	2007
Cumulative Canadian Exploration Expense	53,047	36,872
Cumulative Canadian Development Expense	193,319	183,910
Cumulative Canadian Oil and Gas Property Expense	217,260	187,899
Undepreciated Capital Cost	249,306	217,939
Other	27,741	19,827
Total Canadian tax pools	740,673	646,447
U.S. tax pools	116,785	2,132

Net Income

Net income for the year ended December 31, 2008 was $259.9 million compared to $132.9 million for 2007. The increase is the result of increased production, increased sales prices and unrealized gain on financial instruments, partially offset by increased royalties, and increased loss on foreign exchange and depletion.

Cash Flow from Operations

Cash flow from operations in 2008 increased 52% to $433.8 million from $286.0 million for the previous year. The increase is primarily due to higher production volumes and a 38% increase in average WTI oil price in 2008 compared to 2007. On a barrel of oil equivalent basis, cash flow from operations was $29.46 per boe for 2008 compared to $21.63 per boe for 2007.

Cash Distributions

During 2008, total cash distributions of $2.64 per unit were declared. The monthly cash distribution in 2008 was increased from $0.18 per unit to $0.20 per unit in March and then to $0.25 per unit in June. Distributions were decreased in December 2008 to $0.18 per unit and in February 2009 to $0.12 per unit.

Cash Flow from Operations, Payout Ratio and Distributions

Cash flow from operations and payout ratio are non-GAAP terms. Cash flow from operations represents cash flow from operating activities before changes in non-cash working capital, asset retirement expenditures, and deferred obligations. The Trust's payout ratio is calculated as cash distributions (net of participation in our Distribution Reinvestment Plan ("DRIP")) divided by cash flow from operations. The Trust considers these to be key measures of performance as they demonstrate the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to cash flow from operations (a non-GAAP measure):

($ thousands)	2008	2007
Cash flow from operating activities	$ 471,237	$ 286,450
Change in non-cash working capital	(38,896)	(5,140)
Asset retirement expenditures	1,443	2,442
Decrease in deferred obligations	39	2,278
Cash flow from operations	$ 433,823	$ 286,030
Cash distributions	$ 197,026	$ 145,927
Payout ratio	45%	51%

The Trust does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of oil and gas assets, certain levels of capital expenditures are required to minimize production declines. In the oil and gas industry, due to the nature of reserves reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire oil and natural gas assets increase significantly, it is possible that the Trust would be required to reduce or eliminate its distributions in order to fund capital expenditures. There can be no certainty that the Trust will be able to maintain current production levels in future periods.

Cash distributions declared, net of DRIP participation, of $197.0 million during the year 2008 were funded through cash flow from operations of $433.8 million.

The following table compares cash distributions to cash flow from operating activities and net income:

($ thousands)	2008	2007
Cash flow from operating activities	$ 471,237	$ 286,450
Cash distributions declared	197,026	145,927
Excess of cash flow from operating activities over cash distributions declared	$ 274,211	$ 140,523
Net income	$ 259,894	$ 132,860
Cash distributions declared	197,026	145,927
Excess (shortfall) of net income over cash distributions declared	$ 62,868	$ (13,067)

It is Baytex's long-term operating objective to substantially fund cash distributions and capital expenditures for exploration and development activities through cash flow from operating activities. Future production levels are highly dependant upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized are the main factors influencing the sustainability of our cash distributions. During periods of lower commodity prices, or periods of higher capital spending for acquisitions, it is possible that internally generated cash flow will not be sufficient to fund both cash distributions and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing. As at December 31, 2008, Baytex had approximately $183 million in available undrawn credit facilities to fund such shortfall. As Baytex strives to maintain a consistent distribution level under the guidance of prudent financial parameters, there may be times when a portion of our cash distributions would represent a return of capital.

For the year ended December 31, 2008, the Trust's net income exceeded distributions declared by $62.9 million with net income reduced by $211.3 million of non-cash items and asset retirement expenditures. Non-cash items such as depletion, depreciation and accretion are not fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions. Other non-cash charges, such as unrealized losses on financial instruments and unrealized foreign exchange losses, reduce the net income of a current period, but may not have the same impact on future periods' cash flow. Accordingly, net income is not a fair representation of the Trust's ability to fund our distributions and capital programs.

Liquidity and Capital Resources

The current worldwide economic crisis has resulted in disruptions in the availability of credit on commercially acceptable terms. In light of this situation, we have undertaken a thorough review of our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our ongoing short, medium and long-term commitments. Specifically, we believe that our internally generated cash flow from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium, and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business and, where necessary, we have implemented enhanced credit protection with certain of these counterparties.

At December 31, 2008, total monetary debt was $533.0 million compared to $444.1 million at the end of 2007. Included in this increase is a $42.6 million unrealized foreign exchange loss related to the translation of our U.S. dollar denominated notes Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures. Bank borrowings and working capital deficiency at the end of 2008 were $302.5 million compared to total credit facilities of $485.0 million.

Baytex has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The syndicated credit facilities were increased from $370.0 million to $485.0 million in June 2008. The facilities are subject to semi-annual review and are secured by a floating charge over all of Baytex's assets. The credit facilities mature on July 1, 2009, and are eligible for extension.

Baytex's credit facilities are available pursuant to an agreement with a syndicate of nine financial institutions. Of the nine syndicate members in our facilities, five are major Canadian banks which represent $275 million or 57% of the commitments under the $485 million facilities. We have had preliminary discussions with members of our lending syndicate, and have no reason to believe that the facilities will not be extended upon maturity; however, the amount of the facilities available upon extension has not yet been determined. Under the terms of our credit agreement, we may make a formal request for extension as early as April 1, 2009. A copy of our credit agreement and the first amendment agreement is accessible on the SEDAR website at www.sedar.com (filed on March 28, 2008 and September 15, 2008).

Baytex has US$179.7 million of 9.625% senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to Baytex's bank credit facilities.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders if the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities or the U.S. dollar senior subordinated notes.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary and the Trust has the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices.

Capital Expenditures

Capital expenditures during 2008 totaled $450.2 million, with $185.1 million spent on exploration and development activities, $180.5 million on corporate acquisitions and $84.6 million spent on property acquisitions (net of dispositions). For the year ended December 31, 2008, in Canada the Trust participated in the drilling of 142 (125.8 net) wells, resulting in 113 (102.1 net) oil wells, 17 (12.3 net) gas wells, 6 (5.4 net) stratigraphic test and service wells and 6 (6.0 net) dry holes compared to prior year activities of 136 (127.9 net) wells, including 103 (98.3 net) oil

wells, 20 (16.8 net) gas wells, 7 (6.8 net) stratigraphic test wells and 6 (6.0 net) dry holes. In the U.S., the Trust participated in the drilling of 10 (4.5 net) wells, resulting in 9 (3.6 net) oil wells and 1 (0.9 net) dry hole.

($ thousands)	2008	2007
Land	**9,534**	7,253
Seismic	**4,947**	1,994
Drilling and completion	**132,296**	108,106
Equipment	**34,720**	26,624
Other	**3,586**	4,742
Total exploration and development	**185,083**	148,719
Corporate acquisition (net of working capital)	**180,467**	243,273
Property acquisitions	**84,826**	2,877
Property dispositions	**(194)**	(723)
Total capital expenditures	**450,182**	394,146

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has a number of financial obligations in the ordinary course of business. These obligations are of a recurring and consistent nature and impact the Trust's cash flows in an ongoing manner. A significant portion of these obligations will be funded through operating cash flow. These obligations as of December 31, 2008, and the expected timing of funding of these obligations are noted in the table below.

($ thousands)	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	–	–	–
Distributions payable to unitholders	17,583	17,583	–	–	–
Bank loan(1)	208,482	208,482	–	–	–
Long-term debt(2)	220,362	–	220,362	–	–
Convertible debentures(2)	10,398	–	10,398	–	–
Deferred obligations	74	46	23	5	–
Operating leases	42,732	2,776	7,112	7,887	24,957
Processing and transportation agreements	22,350	8,478	13,631	241	–
Total	686,260	401,644	251,526	8,133	24,957

(1) The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009; however, the amount of the facilities available upon extension has not yet been determined.

(2) Principal amount of instruments.

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

The Trust also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of units. On October 18, 2004, the Trust implemented a DRIP under which Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units may be issued from treasury at 95% of the "weighted average closing price" or acquired on the market at prevailing market prices. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Non-controlling Interest

Baytex is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by Baytex for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008 of 1.79560. As at December 31, 2008, there were no exchangeable shares outstanding.

Financial Instruments and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Board of Directors of the Company (the "Board"), assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar senior subordinated notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term bankers' acceptance rates.

Details of the risk management contracts in place as at December 31, 2008, and the accounting for the Trust's financial instruments are disclosed in note 16 to the consolidated financial statements. A summary of certain risk factors relating to our business is included in our Annual Information Form for the year ended December 31, 2008 under the Risk Factors section.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 1 and 2 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. The financial and operating results of the Trust incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

The Trust has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535 "Capital Disclosures", Section 3862 "Financial

Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation". These standards were adopted prospectively.

Capital Disclosures

Effective January 1, 2008, the Trust prospectively adopted Section 1535, "Capital Disclosures" which establishes standards for disclosing information about the Trust's capital and how it is managed. It requires disclosures of the Trust's objectives, policies and processes for managing capital, the quantitative data about what the Trust regards as capital, whether the Trust has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The only effect of adopting this standard are disclosures on the Trust's capital and how it is managed and are included in note 18 to the consolidated financial statements.

Financial Instruments – Disclosures, Financial Instruments – Presentation

Effective January 1, 2008, the Trust prospectively adopted Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations." These new accounting standards replaced Section 3861, "Financial Instruments – Disclosure and Presentation." Section 3862 requires additional information regarding the significance of financial instruments for the entity's financial position and performance, and the nature, extent and management of risks arising from financial instruments to which the entity is exposed. The additional disclosures required under these standards are included in note 16 to the consolidated financial statements.

FUTURE ACCOUNTING CHANGES

In February 2008, the CICA issued Section 3064 "Goodwill and Intangible Assets", replacing Section 3062 "Goodwill and Other Intangible Assets" and Section 3450 "Research and Development Costs". The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

In April 2008, the CICA published the exposure draft "Adopting IFRS in Canada". The exposure draft proposes to incorporate International Financial Reporting Standards ("IFRS") into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust is currently reviewing the standards to determine the potential impact on its consolidated financial statements. The Trust has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team. In addition, an external advisor has been retained to assist the Trust in scoping its conversion project. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

In January 2009, the CICA issued Section 1582 "Business Combinations", which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

In January 2009, the CICA issued Section 1601 "Consolidated Financial Statements" and Section 1602 "Non-controlling Interests", which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination.

These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

FOURTH QUARTER 2008

The following discussion reviews the Trust's results of operations for the fourth quarter of 2008.

Production

Light oil and NGL production for the fourth quarter of 2008 decreased by 4% to 7,803 bbl/d from 8,123 bbl/d a year earlier. Heavy oil production for the fourth quarter of 2008 increased by 11% to 24,635 bbl/d from 22,196 bbl/day a year ago due to development drilling in the Seal and Lloydminster area. Natural gas production increased by 7% to 57.6 MMcf/d for the fourth quarter of 2008 as compared to 53.9 MMcf/d for the same period last year primarily due to the acquisition of Burmis in June 2008.

Revenue

Petroleum and natural gas sales decreased 15% to $199.9 million for the fourth quarter of 2008 from $233.9 million for the same period in 2007. Commencing with the first quarter of 2008, Baytex began reporting revenue from our heavy oil sales based on the price of the blend crude sold to the refineries. The cost of the blending diluent is reported as an expense. There is no impact to cash flow compared to the previous practice of reporting revenue based on heavy oil wellhead price net of blending charges.

For the per sales unit calculations, heavy oil sales for the three months ended December 31, 2008 were 345 bbl/d higher (three months ended December 31, 2007 – 1,717 bbl/d higher) than the production for the period due to changes in inventory.

Revenue from light oil and NGL for the fourth quarter of 2008 decreased 29% from the same period a year ago due to a 4% decrease in sales volume and a 26% decrease in wellhead prices. Revenue from heavy oil decreased 19% as the result of a 23% decrease in wellhead prices slightly offset by a 4% increase in sales volume. Revenue from natural gas increased 19% as the result of a 7% increase in volume and a 12% increase in wellhead prices.

During the current quarter, sulphur production averaged 69.4 tonnes per day with an average price of $131 per tonne. Sulphur revenue for the same period a year ago was not material for reporting purposes.

Royalties

Total royalties decreased to $31.7 million for the fourth quarter of 2008 from $32.5 million in 2007. Royalties for the current quarter include $0.2 million related to the production of sulphur. Total royalties for the fourth quarter of 2008 were 19% of oil and gas revenue (excluding sales of heavy oil diluent), as compared to 17% for the same period in 2007. For the fourth quarter of 2008, royalties were 23% of sales for light oil, NGL and natural gas, and 16% of sales for heavy oil (excluding sales of heavy oil diluent), as compared to 20% and 14%, respectively, for the same period last year. Royalties are generally based on well productivity and market index prices in the period, with rates increasing as price and volume increase. Heavy oil royalties increased in 2008 as certain oil sands projects at Seal and Cold Lake reached payout in the third quarter, with the pre-payout royalty of 1% of gross revenue converting to a post-payout 25% net profit interest.

Operating Expenses

Operating expenses for the fourth quarter of 2008 increased to $47.4 million from $38.7 million in the corresponding quarter last year. Operating expenses for the current quarter include $0.1 million related to the production of sulphur. Operating expenses were $12.15 per boe for the fourth quarter of 2008 compared to $10.25 per boe for the fourth quarter of 2007. For the fourth quarter of 2008, operating expenses were $12.88 per boe of light oil, NGL and natural gas, and $11.59 per barrel of heavy oil as compared to $9.67 and $10.66, respectively, for the same period in 2007. In the case of light oil, NGL and natural gas, the largest single driver of the increase in unit operating expense was prior-period adjustments to third-party processing costs, which were responsible for a majority of the quarter-over-quarter increase. Other drivers of the increase were increases in labor costs, fuel, power and property taxes. In the case of heavy oil, the increase in quarter-over-quarter operating expense was due primarily to increased fluid hauling charges.

Transportation and Blending Expenses

Transportation and blending expenses for the fourth quarter of 2008 were $45.7 million compared to $43.9 million for the fourth quarter of 2007. Transportation expenses for the current quarter include $0.4 million related to the transportation of sulphur. Transportation expenses were $3.38 per boe for the fourth quarter of 2008 compared to $2.11 for the same period in 2007. Transportation expenses were $0.48 per boe of light oil, NGL and natural gas and $5.24 per barrel of heavy oil in the fourth quarter of 2008, as compared to $0.67 and $3.15, respectively, for the same period of 2007. The increase in transportation cost per unit was driven by increased long-haul trucking from Seal and higher fuel costs which, as of the fourth quarter of 2008, had yet to fully respond to the decline in benchmark prices.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. Baytex purchases primarily condensate as the blending diluent from industry producers to facilitate the marketing of our heavy oil. In the fourth quarter of 2008, the blending cost was $32.5 million for the purchase of 4,820 bbl/d of condensate at $73.34 per barrel, as compared to 4,062 bbl/d at $96.10 per barrel for the same period last year. The cost of diluent is effectively recovered in the sale price of a blended product.

General and Administrative Expenses

General and administrative expenses for the fourth quarter of 2008 increased to $7.6 million from $6.8 million a year earlier. On a per sales unit basis, these expenses were $1.96 per boe for the fourth quarter of 2008 compared to $1.81 per boe for the same period in 2007. In accordance with our full cost accounting policy, no expenses were capitalized in either period.

Unit-based Compensation Expense

Compensation expense related to our trust unit rights incentive plan was $1.6 million for the fourth quarter of 2008 compared to $1.8 million for the fourth quarter of 2007.

Interest Expense

Interest expense for the fourth quarter of 2008 decreased to $7.9 million compared to $8.6 million in the same quarter last year. The decrease is primarily due to the decrease in prime lending rates and a reduction in the bank loan, partially offset by higher foreign exchange rates on payment of interest on the U.S. dollar denominated debt.

Foreign Exchange

Foreign exchange loss in the fourth quarter of 2008 was $24.8 million compared to a gain of $1.2 million in the fourth quarter of 2007. The 2008 amount is comprised of an unrealized foreign exchange loss of $29.0 million and a realized foreign exchange gain of $4.2 million. The gain in the 2007 period was comprised of an unrealized foreign

exchange gain of $1.5 million and a realized foreign exchange loss of $0.3 million. The current quarter's unrealized loss is based on the translation of the U.S. dollar denominated debt at 0.8166 CAD/USD at December 31, 2008 compared to 0.9435 CAD/USD at September 30, 2008. The prior period gain is based on translation at 1.0120 CAD/USD at December 31, 2007 compared to 1.0037 CAD/USD at September 30, 2007.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion for the fourth quarter of 2008 increased to $61.3 million from $54.1 million for the same quarter in 2007. On a per sales unit basis, the provision for the current quarter was $15.71 per boe compared to $14.33 per boe for the same quarter in 2007. The higher rate is primarily due to the acquisition of Burmis completed in June 2008.

Taxes

Current tax of $1.7 million for the fourth quarter of 2008 is comprised primarily of Saskatchewan capital tax and resource surcharge.

For the fourth quarter of 2008, future tax expense totaled $2.2 million compared to a recovery of $27.7 million in the same period in 2007. As at December 31, 2008, total future tax liability of $217.8 million (December 31, 2007 – $142.4 million) consisted of a $25.4 million current future tax liability (December 31, 2007 – $11.5 million current future tax asset) and a $192.4 million long-term future tax liability (December 31, 2007 – $153.9 million).

Net Income

Net income for the fourth quarter of 2008 was $52.4 million compared to $41.4 million for the fourth quarter in 2007. The increase was the result of the unrealized gain on financial instruments offset by reduced petroleum and natural gas revenue, higher depletion, foreign exchange losses and future tax expense.

Trust Unit Information

As at February 28, 2009, the Trust had 98,212,328 units outstanding.

As at February 28, 2009, the Trust had $10.4 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

Selected Annual Information

($ thousands, except per unit amounts)	**2008**	2007	2006
Financial			
Petroleum and natural gas sales	**1,159,718**	745,885	687,016
Net income(1)	**259,894**	132,860	147,069
Per unit basic(1)	**2.83**	1.66	2.02
Per unit diluted(1)	**2.74**	1.60	1.91
Total assets	**1,812,333**	1,407,150	1,079,629
Total long-term financial liabilities	**227,468**	190,004	228,597
Cash distributions declared per unit	**2.64**	2.16	2.16

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

Overall production for 2008 was 40,239 boe per day which represented a 11% increase from 36,222 boe per day in 2007. Production in 2006 was 34,292 boe per day. Average wellhead prices net of blending costs received were $65.66 per boe during 2008, $46.53 per boe during 2007 and $44.48 per boe during 2006.

Quarterly Information

	2008					2007				
	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Production										
Light oil and NGLs *(bbl/d)*	7,575	7,803	8,377	6,778	7,330	5,483	8,123	6,556	3,705	3,484
Heavy oil *(bbl/d)*	23,530	24,635	24,078	22,905	22,484	22,092	22,196	22,593	21,444	22,129
Total oil and NGLs *(bbl/d)*	31,105	32,438	32,455	29,683	29,814	27,575	30,319	29,149	25,149	25,613
Natural gas *(MMcf/d)*	54.8	57.6	60.5	51.0	50.1	51.9	53.9	53.7	49.3	50.6
Oil equivalent *(boe/d)*	40,239	42,035	42,538	38,179	38,157	36,222	39,304	38,094	33,372	34,041

	2008					2007				
	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Average Prices										
WTI oil *(US$/bbl)*	99.59	58.35	118.36	123.98	97.90	72.31	90.68	75.38	65.03	58.27
Edmonton par oil *($/bbl)*	102.86	63.94	122.77	126.29	97.50	76.35	86.41	80.24	72.15	67.09
BTE light oil *($/bbl)*	88.92	55.31	107.41	109.26	84.91	65.53	74.77	67.82	54.42	51.08
BTE heavy oil *($/bbl)*	65.22	38.93	84.65	78.92	59.65	44.53	50.36	46.18	40.42	40.36
BTE total oil *($/bbl)*	70.94	42.83	90.56	85.82	65.66	48.65	56.55	51.08	42.50	41.82
BTE natural gas *($/Mcf)*	7.92	7.05	8.01	9.29	7.42	6.61	6.31	5.80	7.02	7.43
BTE oil equivalent *($/boe)*	65.66	42.71	80.44	79.15	61.16	46.53	52.45	47.23	42.40	42.51

	2008					2007				
($ thousands, except per unit amounts)	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Financial										
Petroleum and natural gas sales	1,159,718	199,890	363,044	332,336	264,448	745,885	233,856	193,784	156,670	161,575
Cash distributions declared per unit	2.64	0.68	0.75	0.65	0.56	2.16	0.54	0.54	0.54	0.54

Reconciliation of Net Income to Cash Flow from Operations

($ thousands, except per unit amounts)	2008					2007				
	TOTAL 2008	Q4	Q3	Q2	Q1	TOTAL 2007	Q4	Q3	Q2	Q1
Net income[1]	259,894	52,401	137,228	34,417	35,848	132,860	41,353	36,674	31,050	23,783
Items not affecting cash:										
Unit-based compensation	7,812	1,563	2,038	2,129	2,082	7,986	1,810	2,370	1,946	1,860
Unrealized foreign exchange loss (gain)	41,712	29,032	7,306	(1,636)	7,010	(32,574)	(1,526)	(12,263)	(16,495)	(2,290)
Depletion, depreciation and accretion	223,900	61,251	61,250	50,941	50,458	189,512	54,086	51,525	42,541	41,360
Accretion on debentures & notes	1,681	519	439	359	364	2,164	2,059	35	34	36
Unrealized (gain) loss on financial instruments	(119,917)	(86,511)	(89,010)	48,433	7,171	31,320	27,264	(599)	4,005	650
Future tax expense (recovery)	15,383	2,217	25,962	(10,318)	(2,478)	(49,369)	(27,659)	(3,895)	(11,307)	(6,508)
Non-controlling interest	3,358	0	1,373	870	1,115	4,131	1,280	1,110	981	760
Cash flow from operations[2]	433,823	60,472	146,586	125,195	101,570	286,030	98,667	74,957	52,755	59,651
Change in non-cash working capital	38,896	38,667	4,591	(24,141)	19,779	5,140	3,145	(308)	956	1,347
Asset retirement expenditures	(1,443)	(725)	(351)	27	(394)	(2,442)	(1,131)	(351)	(257)	(703)
Decrease in deferred obligations	(39)	(7)	(11)	(11)	(10)	(2,278)	(550)	(576)	(576)	(576)
Cash flow from operating activities	471,237	98,407	150,815	101,070	120,945	286,450	100,131	73,722	52,878	59,719
Net income per unit[1]										
Basic	2.83	0.54	1.44	0.39	0.42	1.66	0.49	0.44	0.41	0.32
Diluted	2.74	0.53	1.39	0.38	0.41	1.60	0.48	0.43	0.39	0.30
Cash flow from operations per unit[2]										
Basic	4.73	0.62	1.53	1.42	1.19	3.57	1.17	0.90	0.69	0.79
Diluted	4.51	0.61	1.47	1.33	1.12	3.54	1.10	0.84	0.65	0.74
Cash flow from operating activities per unit										
Basic	5.14	1.01	1.58	1.14	1.42	3.58	1.19	0.88	0.69	0.79
Diluted	4.89	0.99	1.51	1.07	1.33	3.33	1.11	0.83	0.64	0.74

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.

(2) The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow from operations per unit are not measurements based on GAAP, but are financial terms commonly used in the oil and gas industry. Cash flow from operations represents cash generated from operating activities before changes in non-cash working capital, asset retirement expenditures and decrease in deferred obligations. The Trust's determination of cash flow from operations may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

2009 Guidance

Baytex has set a 2009 exploration and development capital budget of $150 million designed to generate production levels at an annual average of 40,000 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 60 gross wells, including 10 primary horizontal producers in our Seal area in the Peace River oil sands region. The remainder of this budget has been allocated to our conventional oil and gas operations, including the drilling of 18 gross wells. Our 2009 production mix is forecast to be approximately 60% heavy oil, 18% light oil and NGL and 22% natural gas. In addition to the exploration and development capital budget, we expect to incur an additional $10 million for deferred acquisition payments on our North Dakota light oil resource play.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex has entered into the following contracts to provide downside protection to 2009 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – $136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – $172.70	WTI

GAS

	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – CAD 6.30	AECO 7A

Foreign Currency

	Period	Amount	Rate
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	CAD/USD 1.2394 (weighted average)
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345

Physical Sale Contracts

HEAVY OIL

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI x 67.0% (weighted average)
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI × 80.0%
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI less US$10.00

GAS

	Period	Volume	Price
Price Collar	Calendar 2009	5,000 GJ/d	CAD 7.00 – CAD 7.95

POWER

	Period	Volume	Price
Fixed	October 1, 2008 to December 31, 2009	0.6 mw/hr	$78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 mw/hr	$79.92
Fixed	March 1, 2009 to June 30, 2010	0.6 mw/hr	$76.89

Gain or loss on financial derivative contracts comprise realized and unrealized gains or losses on financial instruments that do not meet the accounting definition requirements of an effective hedge, even though the Trust considers all financial derivative contracts to be effective economic hedges. Accordingly, gains and losses on such contracts are shown as a separate category in the statement of income.

Strong commodity prices throughout most of 2008 had a significant impact on the Trust's revenue; however, these strong prices resulted in realized cash losses of $51.4 million for the Trust's oil and natural gas financial derivative contracts. During 2008, the Trust recorded a $8.7 million realized loss on foreign exchange financial derivative contracts due to the strengthening of the U.S. dollar during the year.

The 2008 results of the Trust include an unrealized mark-to-market gain of $119.9 million with a net unrealized mark-to-market asset gain position of $85.7 million. The mark-to-market values represent the market price to buy-out the Trust's contracts as of December 31, 2008 and may be different from what will eventually be realized.

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 16 to the consolidated financial statements for a more detailed description of accounting treatment of these derivative contracts.

Environmental Regulation and Risk

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol (the "Protocol"), which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of Baytex.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects the Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance of the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

The Federal Government and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on Baytex and our operations and financial condition.

Further information regarding environmental regulation is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

The New Royalty Framework

On October 25, 2007, the Alberta government announced the "New Royalty Framework" ("NRF"), which introduced the following changes to Alberta's royalty regime effective January 1, 2009:

- Conventional oil – overall royalty rates increased from the pre-NRF maximum of 30% and 35% for old and new tiers. The NRF rates vary on a sliding scale basis up to 50%, and rate caps have been raised to $120 per barrel for West Texas Intermediate (WTI) crude.
- Natural gas – the Government eliminated "old" and "new" tiers. Royalty rates, pre-NRF at 5% to 35% increased to 5% to 50%, based on a sliding rate formula sensitive to price and production volume, with rate caps at $16.59/GJ.
- Oil Sands – before NRF, the pre-payout royalty rate was 1%. Under the NRF, this rate increased for prices above $55 per barrel, to a maximum of 9% when oil is priced at $120 or higher. Under the previous regime, once an oil sands project reached payout, the 1% royalty converted to a 25% net profits interest. Under the NRF, the net profits interest applies at the rate of 25% when oil is less than $55 per bbl of WTI, and increases for every dollar oil is priced above $55 per barrel to a maximum of 40% when oil is priced at $120 or higher.

On November 19, 2008, the Alberta Government announced transitional amendments to the NRF for certain types of drilling. In general terms, operators will have a one-time option of selecting either the transitional royalty regime or the NRF when drilling a new natural gas or conventional oil well 1,000 to 3,500 metres in depth. The transitional regime effectively caps royalty rates at 30% for those wells which qualify, and reduces the commodity prices and production rates at which the top 50% royalty rate kicks in for oil wells. All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the NRF on January 1, 2014. The transitional regime is not applicable to oil sands projects or to wells producing before January 1, 2009.

On March 3, 2009, the Alberta Government announced a new well incentive program intended to stimulate conventional drilling activity. The incentive program offers a one-year royalty credit for conventional oil and gas wells of $200 per metre drilled with the maximum benefit of the incentive accruing to smaller companies. The program also provides for a maximum 5% royalty for all new wells that begin producing conventional oil and gas between April 1, 2009 and March 31, 2010.

Further information regarding NRF is contained in our Annual Information Form for the year ended December 31, 2008 under the Industry Conditions Section.

Broad-based Federal Tax Reductions

On October 30, 2007 the Federal Government presented the fall economic statement that proposed significant reductions in corporate income tax rates from 22.1% to 15%. The reductions will be phased in between 2008 and 2012. In addition, the Government announced that it plans to collaborate with the provinces and territories to reach a 25% combined federal-provincial-territorial statutory corporate income tax rate. The reduction in the federal rate will also reduce the SIFT tax rate to 28% as compared to the rate of 31.5% previously announced subject to comments below concerning the provincial SIFT tax proposal.

Federal Government's Trust Tax Legislation

In 2007, the Federal Government introduced and passed into law amendments to the Income Tax Act (Canada) that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "SIFT"), such as Baytex, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "**SIFT Rules**"). Subject to the Provincial SIFT Tax Proposal described below, the SIFT Rules currently provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined tax rate of 29.5% in 2011 and 28% in 2012.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may

lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a specified investment flow-through trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount carrying forward to the next year. We did not issue equity in excess of the safe harbour limits during 2006/2007 or 2008. As at December 31, 2008, we had unused safe harbour limit of $596.6 million that was carried forward, resulting in a safe harbour limit of $961.6 million for 2009.

On December 20, 2007, the Minister of Finance announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement, the Minister of Finance indicated that the Federal Government intends to provide legislation in 2008 to permit income trusts to convert to taxable Canadian corporations without any undue tax consequence to investors or the trusts.

On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13%, the provincial component will be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada; and
- that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, we would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011 and 25% in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

In 2008, the Federal Government also introduced draft tax legislation to facilitate the conversion of existing income trusts into corporations on a tax deferred basis and to accelerate the recognition of the "safe harbor" limit. Neither this draft tax legislation nor the Provincial SIFT Tax Proposal was enacted prior to prorogation of parliament in December 31, 2008. Therefore, all bills containing the draft legislation had lapsed as of that date.

Subsequent to the year end, the Federal Government introduced draft tax legislation which included the above mentioned measures as part of Canada's Economic Action Plan. This legislation received Royal assent on March 12, 2009, and was therefore was passed into law. We continue to review the impact of the future taxation of distributions on our business strategy but at this time have made no decision as to the ultimate legal form under which we will operate post 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

Disclosure Controls and Procedures

As of December 31, 2008, an internal evaluation was conducted of the effectiveness of the Trust's "disclosure controls and procedures" (as defined in the United States by Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")). Based on that evaluation, the President and Chief

Executive Officer and the Chief Financial Officer concluded that the Trust's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Trust files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein and accumulated and communicated to the Trust's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Trust's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting

"Internal control over financial reporting" (as defined in the United states by Rule 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely financial information. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Trust. Management has assessed the effectiveness of the Trust's internal control over financial reporting. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that the Trust's internal control over financial reporting was effective as of December 31, 2008. The effectiveness of the Trust's internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche LLP, as reflected in their report for 2008.

No changes were made to our internal control over financial reporting during the year ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's unitholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: our ability to maintain production levels by investing approximately half of our internally generated cash flow; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; development plans for our properties; our heavy oil resource play at Seal, including our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, operating costs and the resource potential of our undeveloped land; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates and average recoveries per well; oil and gas prices and differentials between light, medium and heavy oil prices; the demand for and supply of crude oil and natural gas; the level of natural gas drilling activity in North America; the sufficiency of our capital resources to meet our ongoing short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the extension of our credit

facilities upon maturity; funding sources for our cash distributions and capital program; the timing of funding our financial obligations; the impact of the adoption of new accounting standards on our financial results; our production levels for 2009, including our product mix; our exploration and development capital program for 2009; the timing and allocation of our exploration and development expenditures; the timing and amount of deferred acquisition payments for the North Dakota acquisition; the impact of new environmental regulation; potential changes to our business form; and the taxation of income trusts. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; fluctuations in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; changes in income tax laws, royalty rates and incentive programs relating to the oil and gas industry and income trusts; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2008, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and implemented to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent registered chartered accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Anthony W. Marino
President and Chief Executive Officer
Baytex Energy Ltd.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Ltd.

March 16, 2009

AUDITORS' REPORT

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2008 and 2007 and the consolidated statements of income and comprehensive income, deficit, and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 16, 2009, we reported separately to the Board of Directors of Baytex Energy Ltd. and the Unitholders of Baytex Energy Trust on our audit, conducted in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), of the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 19, Differences Between Canadian and United States Generally Accepted Accounting Principles.

Deloitte & Touche LLP

Calgary, Alberta
March 16, 2009

Deloitte & Touche LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 *(thousands of Canadian dollars)*	2008	2007
ASSETS		
Current assets		
Accounts receivable	$ 87,551	$ 105,176
Crude oil inventory	332	5,997
Financial instruments (note 16)	85,678	–
Future tax asset (note 14)	–	11,525
	173,561	122,698
Petroleum and natural gas properties (note 5)	1,601,017	1,246,697
Goodwill	37,755	37,755
	$ 1,812,333	$ 1,407,150
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 164,279	$ 104,318
Distributions payable to unitholders	17,583	15,217
Bank loan (note 6)	208,482	241,748
Financial instruments (note 16)	–	34,239
Future tax liability (note 14)	25,358	–
	415,702	395,522
Long-term debt (note 7)	217,273	173,854
Convertible debentures (note 8)	10,195	16,150
Asset retirement obligations (note 9)	49,351	45,113
Deferred obligations	74	113
Future tax liability (note 14)	192,411	153,943
	885,006	784,695
Non-controlling interest (note 11)	–	21,235
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	1,129,909	821,624
Conversion feature of debentures (note 8)	498	796
Contributed surplus (note 12)	21,234	18,527
Deficit	(224,314)	(239,727)
	927,327	601,220
	$ 1,812,333	$ 1,407,150

Commitments and contingencies (note 17)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Gregory K. Melchin
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Years Ended December 31 *(thousands of Canadian dollars)*	2008	2007
Revenue		
Petroleum and natural gas	$ 1,159,718	$ 745,885
Royalties	(207,522)	(102,805)
Gain (loss) on financial instruments (note 16)	59,816	(34,484)
	1,012,012	608,596
Expenses		
Operating	172,471	134,696
Transportation and blending	218,706	155,754
General and administrative	29,603	23,565
Unit-based compensation (note 12)	7,812	7,986
Interest (note 7)	32,962	35,162
Foreign exchange loss (gain) (note 15)	37,746	(32,414)
Depletion, depreciation and accretion	223,900	189,512
	723,200	514,261
Income before taxes and non-controlling interest	288,812	94,335
Tax expense (recovery) (note 14)		
Current expense	10,177	6,713
Future expense (recovery)	15,383	(49,369)
	25,560	(42,656)
Income before non-controlling interest	263,252	136,991
Non-controlling interest (note 11)	(3,358)	(4,131)
Net income/Comprehensive income	$ 259,894	$ 132,860

CONSOLIDATED STATEMENTS OF DEFICIT

Years Ended December 31, *(thousands of Canadian dollars, except per unit data)*	2008	2007
Deficit, beginning of year	$ (239,727)	$ (198,520)
Net income	259,894	132,860
Distributions to unitholders	(244,481)	(174,067)
Deficit, end of year	$ (224,314)	$ (239,727)
Net income per trust unit (note 13)		
Basic	$ 2.83	$ 1.66
Diluted	$ 2.74	$ 1.60

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31, *(thousands of Canadian dollars)*	2008	2007
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 259,894	$ 132,860
Items not affecting cash:		
Unit-based compensation (note 12)	7,812	7,986
Unrealized foreign exchange loss (gain) (note 15)	41,712	(32,574)
Depletion, depreciation, and accretion	223,900	189,512
Accretion on debentures and notes (notes 7 & 8)	1,681	2,164
Unrealized (gain) loss on financial instruments (note 16)	(119,917)	31,320
Future tax expense (recovery)	15,383	(49,369)
Non-controlling interest (note 11)	3,358	4,131
	433,823	286,030
Change in non-cash working capital (note 15)	38,896	5,140
Asset retirement expenditures (note 9)	(1,443)	(2,442)
Decrease in deferred obligations	(39)	(2,278)
	471,237	286,450
Financing activities		
(Decrease) increase in bank loan	(33,236)	114,253
Issue of trust units, net of issuance costs (note 10)	10,502	147,221
Payments of distributions	(194,728)	(144,609)
	(217,462)	116,865
Investing activities		
Petroleum and natural gas property expenditures	(185,083)	(148,719)
Corporate acquisition (note 4)	(3,934)	(243,273)
Acquisition of working capital (note 4)	–	(13,229)
Acquisition of petroleum and natural gas properties	(84,826)	(2,877)
Proceeds on disposal of petroleum and natural gas properties	194	723
Change in non-cash working capital (note 15)	19,874	4,060
	(253,775)	(403,315)
Change in cash and cash equivalents during the year	–	–
Cash and cash equivalents, beginning of year	–	–
Cash and cash equivalents, end of year	$ –	$ –

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described in note 2.

Certain comparative figures have been reclassified to conform to the presentation adopted in the current period.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from their respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Goodwill impairment tests involve estimates of the Trust's fair value of the net identifiable assets and liabilities annually. If the fair value is less than the book value, an impairment would be recorded. Fair value of the Trust's net identifiable assets and liabilities are based on external market value and reserve estimates and the related future cash flows which are subject to measurement uncertainty.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments which have an initial maturity date at acquisition of not more than 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized on a country-by-country cost centre basis and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test ("ceiling test"). The ceiling test is a two-stage process which is performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the Trust. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied fair value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. The debt portion will accrete up to the principal balance at maturity. The accretion and the interest paid are expensed as interest expense in the consolidated statements of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Asset Retirement Obligations

The Trust recognizes a liability at the discounted value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The present value of the liability is capitalized as part of the cost of the

related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of income and comprehensive income. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

The accounts of integrated foreign operations are translated using the temporal method, whereby monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date. Non-monetary items are translated at historical rates while revenues and expenses are translated using average rates over the period. Depreciation and amortization of assets is translated at historical exchange rates at the same exchange rates as the assets to which they relate. Translation gains and losses relating to the integrated foreign operations are included in the determination of net income for the period.

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, into one of the following five categories: held-for-trading, loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. Held-for-trading financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

All risk management contracts are recorded in the balance sheet at fair value unless they qualify for the normal sale and normal purchase exemption. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. The Trust has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash and cash equivalents and restricted cash are classified as held-for-trading and are measured at fair value which equals the carrying value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures are classified as other financial liabilities. Upon issuance, the convertible debentures were classified into equity and financial liability components on the balance sheet at their fair value. The financial liability, net of issuance costs, is accreted, which is included within interest expense over the maturity of the debentures using the effective interest rate method.

For financial assets and financial liabilities that are not classified as held-for-trading, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are adjusted to the fair value initially recognized for that financial instrument. These costs are expensed using the effective interest rate method and are recorded within interest expense.

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Trust are related to underlying financial instruments or future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. These instruments are classified as "held-for-trading" unless designated for hedge accounting. For derivative instruments that do not qualify as hedges or are not designated as hedges, the Trust applies the fair value method of accounting by recording an asset or liability on the Consolidated Balance Sheet and recognizes changes in the fair value of the instrument in the Statement of Income and Comprehensive Income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts.

The Trust has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments. This documentation specifically ties the derivative instruments to their use and in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. When applicable, the Trust identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. When specific financial instruments are executed, the Trust assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in a particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Future Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax bases of an asset or liability, using substantively enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 12. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Trust are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest's proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights

were exercised, exchangeable shares were exchanged and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the year.

3. CHANGES IN ACCOUNTING POLICIES

Current Year Accounting Changes

Effective January 1, 2008, the Trust adopted three new accounting standards that were issued by the Canadian Institute of Chartered Accountants ("CICA"): Section 1535, Capital Disclosures, Section 3862, Financial Instruments – Disclosures and Section 3863, Financial Instruments – Presentation.

A. Capital Disclosures

Effective January 1, 2008, the Trust prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") Section 1535, "Capital Disclosures" which establishes standards for disclosing information about the Trust's capital and how it is managed. It requires disclosures of the Trust's objectives, policies and processes for managing capital, the quantitative data about what the Trust regards as capital, whether the Trust has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. The only effect of adopting this standard are disclosures on the Trust's capital and how it is managed and are included in Note 18.

B. Financial Instruments – Disclosures, Financial Instruments – Presentation

Effective January 1, 2008, the Trust prospectively adopted Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations." These new accounting standards replaced Section 3861, "Financial Instruments – Disclosure and Presentation." Section 3862 requires additional information regarding the significance of financial instruments for the entity's financial position and performance, and the nature, extent and management of risks arising from financial instruments to which the entity is exposed. The additional disclosures required under these standards are included in Note 16.

C. Inventories

Section 3031 replaces the previous inventories standard and requires inventory be valued on a first-in, first-out basis. The adoption of Section 3031 did not have an impact on the consolidated financial statements of the Trust.

These standards were adopted prospectively.

Future Accounting Changes

A. Goodwill and Intangible Assets

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. The new Section will be effective on January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section, however does not expect a material impact on its consolidated financial statements.

B. International Financial Reporting Standards ("IFRS")

In April 2008, the CICA published the exposure draft "Adopting IFRSs in Canada". The exposure draft proposes to incorporate IFRS into the CICA Accounting Handbook effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. At this date, publicly accountable enterprises will be required to prepare financial statements in accordance with IFRS. The Trust has performed a diagnostic analysis that identifies differences between the Trust's current accounting policies and IFRS. At this time, the Trust is evaluating the impact of these differences and assessing the need for amendments to existing accounting policies in order to comply with IFRS.

C. Business Combinations

In January 2009, the CICA issued Section 1582, "Business Combinations", which replaces former guidance on business combinations. Section 1582 establishes principles and requirements of the acquisition method for business combinations and related disclosures. This statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt this standard prospectively effective January 1, 2009 and does not expect the adoption of this statement to have a material impact on our results of operations or financial position.

D. Consolidated Financial Statements

In January 2009, the CICA issued Sections 1601, "Consolidated Financial Statements", and 1602, "Non-controlling Interests", which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. These standards are effective on the first annual reporting period beginning on or after January 2011 with earlier application permitted. The Trust plans to adopt these standards effective January 1, 2009 and does not expect the adoption will have a material impact on the results of operations or financial position.

4. CORPORATE ACQUISITIONS

On June 4, 2008, Baytex acquired all the issued and outstanding shares of Burmis Energy Inc., a public company which had interests in certain natural gas and light oil properties located primarily in west central Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 4, 2008. In conjunction with the acquisition, Burmis Energy Inc. was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Trust units issued	$ 152,053
Net debt assumed	24,480
Costs associated with acquisition	3,934
Total purchase price	$ 180,467
Allocation of purchase price:	
Property, plant and equipment	$ 219,913
Future income taxes	(37,910)
Asset retirement obligations	(1,536)
Total net assets acquired	$ 180,467

All of the issued and outstanding shares of Burmis were acquired on the basis of 0.1525 of a Baytex trust unit for each Burmis share, resulting in the issuance of 6,383,416 Baytex trust units valued at $23.82 per unit, which was the average closing price of Baytex trust units for the ten trading days bordering the initial public announcement of the transaction.

On June 26, 2007, Baytex acquired all the issued and outstanding shares of a private company which had interests in certain petroleum and natural gas properties and related assets located primarily in the Pembina and Lindbergh areas of Alberta. The results of operations from these properties have been included in the consolidated financial statements since the closing of the acquisition on June 26, 2007. Subsequent to the acquisition, the private company was amalgamated with the Company.

This transaction has been accounted for using the purchase method of accounting. The fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below:

Consideration for the acquisition:	
Cash paid for property, plant and equipment	$ 241,092
Costs associated with acquisition	2,181
Cash paid for working capital	13,229
Total purchase price	$ 256,502
Allocation of purchase price:	
Working capital	$ 13,229
Property, plant and equipment	320,036
Future income taxes	(74,524)
Asset retirement obligations	(2,239)
Total net assets acquired	$ 256,502

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31,	
	2008	2007
Petroleum and natural gas properties	**$ 3,648,431**	$ 3,074,014
Accumulated depletion and depreciation	**(2,047,414)**	(1,827,317)
	$ 1,601,017	$ 1,246,697

In calculating the Canadian cost centre depletion and depreciation provision for 2008, $63.6 million (2007 – $65.0 million) of costs relating to undeveloped properties were excluded, while $385.0 million (2007 – $427.1 million) of future development costs were included for the purposes of the depletion and depreciation calculation. In calculating the U.S. cost centre depletion and depreciation provision for 2008, $57.6 million (2007 – $nil) of costs relating to undeveloped properties were excluded, while $56.3 million (2007 – $nil) of future development costs were included for the purposes of the depletion and depreciation calculation. No general and administrative expenses have been capitalized since the inception of operations as a trust.

Depletion and depreciation expense related to the Canadian and U.S. cost centers in 2008 were $218.4 million and $1.7 million respectively (2007 – $186.1 million and $nil).

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2008 using the following benchmark reference prices for the years 2009 to 2013 adjusted for commodity differentials specific to the Trust (notes 16 & 17):

	2009	2010	2011	2012	2013
WTI crude oil (US$/bbl)	53.73	63.41	69.53	79.59	92.01
AECO natural gas ($/MMBtu)	6.82	7.56	7.84	8.38	9.20
Henry Hub (US$/MMBtu)	6.30	7.32	7.56	8.49	9.74
Exchange rate ($US equals $1 CAD)	0.80	0.85	0.85	0.90	0.95

The prices and costs subsequent to 2013 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculations, the Trust's estimated undiscounted future net cash flows associated with proved reserves plus the cost of unproved properties exceeded the net book value of the petroleum and natural gas properties.

6. BANK LOAN AND CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit (note 17) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. Effective June 4, 2008, total credit facilities were increased to $485 million from $370 million. The credit facilities are subject to semi-annual

review and are secured by a floating charge over all of the Company's assets. The credit facilities mature on July 1, 2009 and are eligible for extension. At December 31, 2008 a total of $208.5 million was drawn under the credit facilities (December 31, 2007 – $241.7 million).

7. LONG-TERM DEBT

	As at December 31	
	2008	2007
10.5% senior subordinated notes (US$247)	$ 303	$ 244
9.625% senior subordinated notes (US$179,699)	220,059	177,561
	220,362	177,805
Discontinued fair value hedge	(3,089)	(3,951)
	$ 217,273	$ 173,854

The Company has US$0.2 million senior subordinated notes bearing interest at 10.5% payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

The Company also has US$179.7 million senior subordinated notes bearing interest at 9.625% payable semi-annually with principal repayable on July 15, 2010. These notes are unsecured and are subordinate to the Company's bank credit facilities. After July 15 in each of the following years, these notes are redeemable at the Company's option, in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as percentage of the principal amount of the notes): 2008 at 102.406%, 2009 and thereafter at 100%. These notes are carried at amortized cost net of a discontinued fair value hedge of $6.0 million recorded on adoption of CICA Handbook Section 3865 "Hedges". The notes will accrete up to the principal balance at maturity using the effective interest method. Accretion expense of $1.6 million had been recorded for the year ended December 31, 2008 (December 31, 2007 – $2.0 million) The effective interest rate is 10.6%. The Company had an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2% until the maturity of these notes. In November 2007, the Company terminated the interest rate swap contract. A gain on termination of $2.0 million was recorded as a reduction to interest expense in 2007.

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

	2008	2007
Bank loan and miscellaneous financing	$ 12,685	$ 13,296
Convertible debentures	945	1,295
Long-term debt	19,332	20,571
Total interest	$ 32,962	$ 35,162

8. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010, at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. The debt portion will accrete up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid are expensed as interest expense in the consolidated statement of income and comprehensive income. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

	Number of Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, December 31, 2006	19,619	$ 18,906	$ 940
Conversion	(2,999)	(2,895)	(144)
Accretion	–	139	–
Balance, December 31, 2007	16,620	$ 16,150	$ 796
Conversion	(6,222)	(6,052)	(298)
Accretion	–	97	–
Balance, December 31, 2008	**10,398**	**$ 10,195**	**$ 498**

9. ASSET RETIREMENT OBLIGATIONS

	As at December 31,	
	2008	2007
Balance, beginning of year	**$ 45,113**	$ 39,855
Liabilities incurred	**871**	2,180
Liabilities settled	**(1,443)**	(2,442)
Acquisition of liabilities	**1,536**	2,239
Disposition of liabilities	**(904)**	(585)
Accretion	**3,802**	3,404
Change in estimate[1]	**376**	462
Balance, end of year	**$ 49,351**	$ 45,113

(1) Change in status of wells and change in the estimated costs of abandonment and reclamations are factors resulting in a change in estimate.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2008 is $274.0 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an estimated annual inflation rate of 2.0 percent.

10. UNITHOLDERS' CAPITAL

The Trust is authorized to issue an unlimited number of trust units.

	Number of units	Amount
Balance, December 31, 2006	75,122	$ 637,156
Issued from treasury for cash	7,000	142,135
Issued on conversion of debentures	203	3,037
Issued on conversion of exchangeable shares	12	230
Issued on exercise of trust unit rights	739	5,482
Transfer from contributed surplus on exercise of trust unit rights	–	2,816
Issued pursuant to distribution reinvestment plan	1,464	27,763
Cumulative effect of change in accounting policy	–	3,005
Balance, December 31, 2007	84,540	821,624
Issued on conversion of debentures	422	6,350
Issued on conversion of exchangeable shares	2,787	86,888
Issued on exercise of trust unit rights	1,386	10,653
Transfer from contributed surplus on exercise of trust unit rights	–	5,105
Issued on acquisition of Burmis Energy Inc. net of issuance costs	6,383	151,903
Issued pursuant to distribution reinvestment plan	2,167	47,386
Balance, December 31, 2008	**97,685**	**$ 1,129,909**

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 90 percent of the "market price" of the trust units on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $250,000 per month. Redemptions in excess of the cash limit, if not waived by the Trust, shall be satisfied by distribution of subordinate, unsecured redemption notes bearing interest at 12% per annum, due and payable no later than September 1, 2033.

11. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either a cash payment or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly to account for distributions paid on the trust units by dividing the cash distribution paid by the weighted average trust unit price for the five-day trading period ending on the record date. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

	Number of Exchangeable Shares	Amount
Balance, December 31, 2006	1,573	$ 17,187
Exchanged for trust units	(7)	(83)
Non-controlling interest in net income	–	4,131
Balance, December 31, 2007	1,566	$ 21,235
Exchanged for trust units	(1,566)	(24,593)
Non-controlling interest in net income	–	3,358
Balance, December 31, 2008	–	$ –

On May 30, 2008, the Trust announced that Baytex Energy Ltd. had elected to redeem all of its exchangeable shares outstanding on August 29, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such exchangeable shares from holders of record. Each exchangeable share was exchanged for units of the Trust in accordance with the exchange ratio in effect at August 28, 2008. As at December 31, 2008, there were no exchangeable shares outstanding.

12. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the Plan is a "rolling" maximum equal to 10.0% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units will result in an increase in the number of trust units available for issuance under the Plan, and any exercises of rights will make new grants available under the Plan, effectively resulting in a re-loading of the number of rights available to grant under the Plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a

term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $7.8 million for the year ended December 31, 2008 ($8.0 million in 2007) related to the rights granted under the plan.

The Trust uses the binomial-lattice model to calculate the estimated weighted average fair value of $2.42 per unit for rights issued during 2008 ($3.87 per unit in 2007). The following assumptions were used to arrive at the estimate of fair values:

	2008	2007
Expected annual right's exercise price reduction	$2.64	$2.16
Expected volatility	28% – 39%	28%
Risk-free interest rate	2.98% – 4.17%	3.77% – 4.50%
Expected life of right (years)	Various(1)	Various(1)

(1) *The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Trust Unit Rights Incentive Plan.*

The number of unit rights outstanding and exercise prices are detailed below:

	Number of rights	Weighted average exercise price(1)
Balance, December 31, 2006	6,313	$ 14.00
Granted	2,642	$ 19.85
Exercised	(739)	$ 7.42
Cancelled	(554)	$ 16.91
Balance, December 31, 2007	7,662	$ 14.67
Granted	2,838	$ 19.27
Exercised	(1,386)	$ 7.69
Cancelled	(665)	$ 21.79
Balance, December 31, 2008	8,449	$ 14.58

(1) *Exercise price reflects grant prices less reduction in exercise price as discussed above.*

The following table summarizes information about the unit rights outstanding at December 31, 2008:

Range of Exercise Prices	Number Outstanding at December 31, 2008	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Exercisable at December 31, 2008	Weighted Average Exercise Price
		(years)			
$1.00 to $6.00	706	0.9	$ 3.71	706	$ 3.71
$6.01 to $11.00	1,352	1.8	$ 8.35	1,254	$ 8.17
$11.01 to $16.00	399	3.2	$ 15.08	183	$ 15.14
$16.01 to $21.00	5,947	3.9	$ 17.18	1,637	$ 17.05
$21.01 to $32.28	45	4.4	$ 25.93	–	–
$1.00 to $32.28	8,449	3.3	$ 14.58	3,780	$ 11.52

The following table summarizes the changes in contributed surplus:

Balance, December 31, 2006	$ 13,357
Compensation expense	7,986
Transfer from contributed surplus on exercise of trust unit rights(1)	(2,816)
Balance, December 31, 2007	$ 18,527
Compensation expense	7,812
Transfer from contributed surplus on exercise of trust unit rights(1)	(5,105)
Balance, December 31, 2008	$ 21,234

(1) *Upon exercise of rights, contributed surplus is reduced with a corresponding increase in unitholders' capital.*

13. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

2008	Net income	Trust units	Net income per trust unit
Net income per basic unit	$ 259,894	91,683	$ 2.83
Dilutive effect of trust unit rights	–	2,955	
Conversion of convertible debentures	654	882	
Exchange of exchangeable shares	3,358	871	
Net income per diluted unit	$ 263,906	96,391	$ 2.74

2007	Net income	Trust units	Net income per trust unit
Net income per basic unit	$ 132,860	80,029	$ 1.66
Dilutive effect of trust unit rights	–	2,110	
Conversion of convertible debentures	855	1,206	
Exchange of exchangeable shares	4,131	2,630	
Net income per diluted unit	$ 137,846	85,975	$ 1.60

The dilutive effect of trust unit incentive rights for the year ended December 31, 2008 did not include 45,000 trust unit rights (2007 – 4.1 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services and not yet recognized exceeded the average market price of the trust units during the year.

14. TAX EXPENSE (RECOVERY)

The provision for (recovery of) taxes has been computed as follows:

	2008	2007
Income before taxes and non-controlling interest	$ 288,812	$ 94,335
Expected taxes at the statutory rate of 30.22% (2007 – 34.02%)	87,279	32,094
Increase (decrease) in taxes resulting from:		
Net income of the Trust	(79,930)	(62,615)
Non-taxable portion of foreign exchange loss (gain)	6,204	(5,424)
Effect of change in tax rate	(1,402)	(15,806)
Effect of change in opening tax pool balances	878	(834)
Effect of change in valuation allowance	–	2,075
Unit-based compensation	2,361	2,717
Other	(7)	(1,576)
Future tax expense (recovery)	15,383	(49,369)
Current tax expense	10,177	6,713
Total tax expense (recovery)	$ 25,560	$ (42,656)

On June 22, 2007, Bill C-52 Budget Implementation Act, which contains legislative provisions to tax publicly traded income trusts in Canada, received Royal Assent in the Canadian House of Commons. The new tax is not expected to apply to the Trust until 2011. As a result of the tax legislation becoming enacted, an additional future tax recovery of $0.5 million was recorded in 2007.

The components of the net future tax liability at December 31 were as follows:

	2008	2007
Future tax liabilities:		
Petroleum and natural gas properties	$ 197,694	$ 155,921
Financial instruments	25,358	–
Other	14,215	18,271
Future tax assets:		
Asset retirement obligations	(12,652)	(11,796)
Non-capital loss carry-forward	(11,813)	(8,058)
Valuation allowance on non-capital losses	4,967	–
Financial instruments	–	(11,525)
Other	–	(395)
Net future tax liability(1)	217,769	142,418
Current portion of net future tax liability (asset)	25,358	(11,525)
Long-term portion of net future tax liability	$ 192,411	$ 153,943

(1) Non-capital loss carry-forwards, excluding those for which a valuation allowance has been taken, amongst Canadian and U.S. subsidiaries, totaled $42.9 million ($62.0 million in 2007) and expire from 2014 to 2017.

15. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	2008	2007
Current assets	$ 35,460	$ (23,619)
Current liabilities	23,310	32,819
	$ 58,770	$ 9,200
Changes in non-cash working capital related to:		
Operating activities	$ 38,896	$ 5,140
Investing activities	19,874	4,060
	$ 58,770	$ 9,200

Supplemental Cash Flow Information

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes:

	2008	2007
Interest	$ 30,655	$ 32,321
Current income taxes	$ 9,972	$ 9,436

Foreign Exchange Loss (Gain)

	2008	2007
Unrealized foreign exchange loss (gain)	$ 41,712	$ (32,574)
Realized foreign exchange (gain) loss	(3,966)	160
Total foreign exchange loss (gain)	$ 37,746	$ (32,414)

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Trust's financial assets and liabilities are comprised of accounts receivable, accounts payable and accrued liabilities, distributions payable to unitholders, bank loan, financial derivative contracts, long-term debt, convertible debentures and deferred obligations.

Categories of Financial Instruments

Under Canadian generally accepted accounting principles, financial instruments are classified into one of the following 5 categories: held-for-trading, held to maturity, loans and receivables, available-for-sale and other financial liabilities. The carrying value and fair value of the Trust's financial instruments on the consolidated balance sheet are classified into the following categories:

	December 31, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Loans and receivables				
Accounts receivable	$ 87,551	$ 87,551	$ 105,176	$ 105,176
Total loans and receivables	$ 87,551	$ 87,551	$ 105,176	$ 105,176
Held for trading				
Derivatives designated as held for trading	$ 85,678	$ 85,678	–	–
Total held for trading	$ 85,678	$ 85,678	–	–
Financial Liabilities				
Held for trading				
Derivatives designated as held for trading	–	–	$ (34,239)	$ (34,239)
Total held for trading	–	–	$ (34,239)	$ (34,239)
Other financial liabilities				
Accounts payable and accrued liabilities	$ (164,279)	$ (164,279)	$ (104,318)	$ (104,318)
Distributions payable to unitholders	(17,583)	(17,583)	(15,217)	(15,217)
Bank loan	(208,482)	(208,482)	(241,748)	(241,748)
Long-term debt	(217,273)	(200,557)	(173,854)	(182,132)
Convertible debentures	(10,195)	(9,837)	(16,150)	(19,481)
Deferred obligations	(74)	(74)	(113)	(113)
Total other financial liabilities	$ (617,886)	$ (600,812)	$ (551,400)	$ (563,009)

The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than bank loan, and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its book value as it is at a market rate of interest. The fair value of the long-term debt is based on the trading value of the instrument. The fair value of the convertible debentures has been calculated based on the lower of trading value and the present value of future cash flows associated with the debentures.

Financial Risk

The Trust is exposed to a variety of financial risk, including market risk, credit risk and liquidity risk. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk

The Trust is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated notes, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Trust's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

In order to manage these risks, the Trust may enter into agreements to fix the exchange rate of Canadian to U.S. dollar in order to lessen the impact of currency rate fluctuations.

At December 31, 2008, the Trust had in place the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 8.3 million per month	CAD/USD 1.2394 (weighted average)

The following table demonstrates the effect of exchange rate movement on net income before taxes and non-controlling interest due to changes in the fair value of its currency swap as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2008.

	$0.10 Increase/Decrease in CAD/USD Exchange Rate
Gain/loss on currency swap	$ (189)
Gain/loss on other monetary assets/liabilities	10,939
Impact on income before taxes and non-controlling interest	$ 10,750

The carrying amounts of the Trust's foreign currency denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2008	December 31, 2007	**December 31, 2008**	December 31, 2007
U.S. dollar denominated	**USD 84,070**	USD 54,674	**USD 191,571**	USD 226,528

Subsequent to December 31, 2008, the Trust added the following currency swap:

	Period	Amount	Swap Price
Swap	January 1, 2009 to December 31, 2009	USD 1.7 million per month	CAD/USD 1.2345

Interest rate risk

The Trust's interest rate risk arises from its floating rate bank loan. As at December 31, 2008, $208.5 million of the Trust's total debt is subject to movements in floating interest rates. An increase or decrease of 1.0% in interest rates would impact cash flow for the 2008 by approximately $2.2 million.

Commodity Price Risk

The Trust monitors and, when appropriate, utilizes financial derivative agreements or fixed price physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of the Company. Under the Trust's risk management policy, financial instruments are not used for speculative purposes.

When assessing the potential impact of commodity price changes, a 10% increase in commodity prices could have resulted in a reduction to the unrealized gain in 2008 of $8.5 million relating to the financial derivative instruments outstanding as at December 31, 2008, while a 10% decrease could have resulted in $8.8 million of additional gain.

At December 31, 2008, the Trust had the following commodity derivative contracts:

Oil

	Period	Volume	Price	Index
Price collar	Calendar 2009	2,000 bbl/d	USD 90.00 – 136.40	WTI
Price collar	Calendar 2009	2,000 bbl/d	USD 110.00 – 172.70	WTI

Derivative contracts are marked to market at the end of each reporting period, with the following reflected in the income statement:

	2008	2007
Realized (loss) on financial instruments	**$ (60,101)**	$ (3,164)
Unrealized gain (loss) on financial instruments	**119,917**	(31,320)
Gain (loss) on financial instruments	**$ 59,816**	$ (34,484)

Subsequent to December 31, 2008, the Trust added the following commodity derivative contract:

Gas

	Period	Volume	Price	Index
Price collar	April 1, 2009 to December 31, 2010	5,000 GJ/d	CAD 5.00 – 6.30	AECO

Liquidity risk

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with financial liabilities. The Trust manages its liquidity risk through cash and debt management. As at December 31, 2008, the Trust had available unused bank credit facilities in the amount of $183 million. The Trust believes it has sufficient funding capacity through its credit facilities to meet foreseeable borrowing requirements.

The timing of cash outflows (excluding interest) relating to financial liabilities are outlined in the table below:

	Total	1 year	2-3 years	4-5 years	Beyond 5 years
Accounts payable and accrued liabilities	164,279	164,279	–	–	–
Distributions payable to unitholders	17,583	17,583	–	–	–
Bank loan[1]	208,482	208,482	–	–	–
Long-term debt[2]	220,362	–	220,362	–	–
Convertible debentures[2]	10,398	–	10,398	–	–
Deferred obligations	74	46	23	5	–
	621,178	390,390	230,783	5	–

(1) *The bank loan is a 364-day revolving loan with the ability to extend the term. The Trust has no reason to believe that it will be unable to extend the credit facility when it matures on July 1, 2009.*

(2) *Principal amount of instruments.*

Credit risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in the Trust incurring a loss. Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income.

As at December 31, 2008, accounts receivable consists of a balance of $9.9 million which is over 90 days (December 31, 2007 – $3.5 million). A balance of $2.4 million has been set up as an allowance for doubtful accounts (December 31, 2007 – $0.2 million).

17. COMMITMENTS AND CONTINGENCIES

At December 31, 2008, the Trust had the following crude oil supply contracts:

Heavy Oil

	Period	Volume	Price
Price Swap – WCS Blend	Calendar 2009	10,340 bbl/d	WTI × 67.0% (weighted average)

Subsequent to December 31, 2008, the Trust added the following physical crude oil supply contracts:

Heavy Oil

	Period	Volume	Price
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI × 80.0%
Price Swap – WCS Blend	April 1, 2009 to August 30, 2009	775 bbl/d	WTI less US $10.00

At December 31, 2008, the Trust had the following natural gas physical sales contract:

Gas

	Period	Volume	Price/GJ
Price Collar	Calendar 2009	5,000 GJ/d	$ 7.00 – $ 7.95

At December 31, 2008, the Trust had the following power contracts:

Power

	Period	Volume	Price/MWh
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$ 78.61
Fixed	October 1, 2008 to December 31, 2009	0.6 MW/hr	$ 79.92

Subsequent to December 31, 2008, the Trust added the following physical power contract:

Power

	Period	Volume	Price/MWh
Fixed	March 1, 2009 to June 30, 2010	0.6 MW/hr	$ 76.89

At December 31, 2008, the Trust had operating lease and transportation obligations as summarized below:

	Payments Due						
	Total	1 year	2 years	3 years	4 years	5 years	Beyond 5 years
Operating leases	$ 42,732	$ 2,776	$ 3,327	$ 3,785	$ 4,073	$ 3,814	$ 24,957
Processing and transportation agreements	22,350	8,478	7,435	6,196	178	63	–
Total	$ 65,082	$ 11,254	$ 10,762	$ 9,981	$ 4,251	$ 3,877	$ 24,957

Other

At December 31, 2008, there were outstanding letters of credit aggregating $2.3 million (December 31, 2007 – $4.9 million) issued as security for performance under certain contracts.

In connection with a purchase of properties in 2005, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. An amount payable was not reasonably determinable at the time of the purchase, therefore such consideration should be recognized only when the contingency is resolved. As at December 31, 2008, additional payments totaling $5.3 million have been paid under the agreement and have been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

18. CAPITAL STRUCTURE

The Trust's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

The Trust considers its capital structure to include total monetary debt and unitholders' equity. Total monetary debt is a non-GAAP term which we define to be the sum of monetary working capital, which is current assets less current liabilities excluding non-cash items such as future income tax assets or liabilities and unrealized financial derivative gains or losses, the principal amount of long-term debt and the balance sheet value of the convertible debentures.

The Trust's financial strategy is designed to maintain a flexible capital structure consistent with the objectives above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to maintain the capital structure, the Trust may adjust the amount of its distributions, adjust its level of capital spending, issue new units, issue new debt or sell assets to reduce debt.

The Trust monitors capital based on current and projected ratios of total monetary debt to cash flow, and the current and projected level of its undrawn bank credit facilities. The Trust's objectives are to maintain a total monetary debt to cash flow from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to cash flow from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to cash flow from operations ratio and the level of undrawn bank credit facilities, the Trust continuously monitors its cash flow from operations and evaluates its distribution policy and capital spending plans.

The Trust's financial objectives and strategy as described above have remained substantially unchanged over the last two completed fiscal years. These objectives and strategy are reviewed on an annual basis. The Trust believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

The Trust is subject to financial covenants relating to its bank loan, senior subordinated notes and convertible debentures. The Trust is in compliance with all financial covenants.

On June 22, 2007, new tax legislation modifying the taxation of specified investment flow-through entities, including income trusts such as the Trust, was enacted (the "New Tax Legislation"). The New Tax Legislation will apply a tax at the trust level on distributions of certain income from trusts. The New Tax Legislation permits "normal growth" for income trusts through the transitional period ending December 31, 2010. However, "undue expansion" could cause the transitional relief to be revisited, and the New Tax Legislation to be effective at a date earlier than January 1, 2011. On December 15, 2006, the Department of Finance released guidelines on normal growth for income trusts and other flow-through entities (the "Guidelines"). Under the Guidelines, trusts will be able to increase their equity capital each year during the transitional period by an amount equal to a safe harbor amount. The safe harbor amount is measured by reference to a trust's market capitalization as of the end of trading on October 31, 2006. The safe harbor amounts are 40% for the period from November 2006 to the end of 2007, and 20% per year for each of 2008, 2009 and 2010. For Baytex, the limits are approximately $730 million for 2006/2007 and $365 million for each of the subsequent three years. The safe harbor amounts are cumulative allowing amounts not used in one year to be carried forward to a future year. Two trusts can merge without being impacted by the growth limitations. Limits are not impacted by non-convertible debt-financed growth, but rather focus solely on the issuance of equity to facilitate growth. At December 31, 2008, the Trust had not exceeded its "normal growth" limits.

19. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The significant differences between Canadian and United States GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

RESERVES INFORMATION

The following table summarizes certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2008. Additional information required under NI 51-101 is included in the Annual Information Form for fiscal 2008.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

	Light and Medium Oil		Heavy Oil		Bitumen	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
PROVED:						
Developed Producing	7,894	5,814	28,430	23,487	–	–
Developed Non-Producing	901	666	20,923	17,140	–	–
Undeveloped	6,234	4,898	37,584	30,712	–	–
TOTAL PROVED	15,030	11,379	86,937	71,339	–	–
PROBABLE	10,784	7,925	36,653	29,951	2,464	2,083
TOTAL PROVED PLUS PROBABLE	25,814	19,304	123,590	101,289	2,464	2,083

Notes:

(1) *"Gross" reserves are the working interest share of remaining reserves, before deduction of any royalties and excluding any royalty interest.*

(2) *"Net" reserves means Baytex's gross reserves less all royalties payable to others.*

(3) *Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Reconciliation of Working Interest Reserves(1)
By Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil			Heavy Oil		
	Proved(2)	Probable(2)	Proved + Probable(2)	Proved(2)	Probable(2)	Proved + Probable(2)
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2007	10,037	5,295	15,332	85,069	37,393	122,461
Extensions	–	–	–	410	334	743
Discoveries	–	–	–	38	15	53
Improved Recovery	467	3,615	4,083	3,306	7,381	10,686
Technical Revisions	2,017	(330)	1,687	6,269	(8,819)	(2,550)
Acquisitions	4,604	2,191	6,795	81	86	167
Dispositions	–	–	–	–	–	–
Economic Factors	37	13	50	487	263	750
Production	(2,133)	–	(2,133)	(8,722)	–	(8,722)
December 31, 2008	15,030	10,784	25,813	86,937	36,653	123,590

Notes:

(1) *Company interest reserves include solution gas but do not include royalty interest.*

(2) *Reserves information as at December 31, 2008 and 2007 is prepared in accordance with NI 51-101.*

(3) *Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

(4) *Bitumen relates to probable reserves attributed to thermal production.*

Natural Gas Liquids		Natural Gas		Total Reserves[3]	
Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
(Mbbl)	(Mbbl)	(Bcf)	(Bcf)	(Mboe)	(Mboe)
2,756	2,100	87,726	70,059	53,702	43,078
594	433	16,805	11,516	25,219	20,158
375	275	15,446	12,449	46,768	37,960
3,726	2,808	119,977	94,024	125,688	101,196
1,846	1,381	58,226	43,379	61,451	48,570
5,572	4,189	178,203	137,403	187,139	149,765

Bitumen[4]			Natural Gas Liquids			Associated and Non-Associated Gas			Oil Equivalent[3]		
roved[2]	Probable[2]	Proved + Probable[2]	Proved[2]	Probable[2]	Proved + Probable[2]	Proved[2]	Probable[2]	Proved + Probable[2]	Proved[2]	Probable[2]	Proved + Probable[2]
(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
–	–	–	3,603	1,870	5,473	103,969	44,888	148,857	116,038	52,038	168,076
–	–	–	32	6	38	248	393	641	483	406	889
–	–	–	–	–	–	–	–	–	38	15	53
–	2,464	2,464	166	68	233	6,756	5,121	11,877	5,065	14,380	19,445
–	–	–	(504)	(563)	(1,066)	(6,053)	(7,620)	(13,673)	6,774	(10,982)	(4,209)
–	–	–	1,032	445	1,477	33,879	14,894	48,773	11,364	5,204	16,568
–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	35	22	58	1,233	551	1,784	764	391	1,155
–	–	–	(640)	–	(640)	(20,058)	–	(20,058)	(14,837)	–	(14,837)
–	–	–	3,726	1,846	5,572	119,976	58,226	178,202	125,688	61,451	187,139

Reserve Life Index

	2009 Production Target	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL (bbl/d)	30,700	9.5	14.1
Natural Gas (MMcf/d)	56.0	5.9	8.7
Oil Equivalent (boe/d)	40,000	8.6	12.8

Net Present Value of Reserves (forecast prices and costs)

Reserves Category *($ million)*	Summary of Net Present Value of Future Net Revenue As at December 31, 2008 Forecast Prices and Costs Before Income Taxes Discounted at (%/year)(1) 0%	5%	10%
Proved			
Developed Producing	1,644	1,370	1,183
Developed Non-Producing	945	676	507
Undeveloped	1,571	1,078	779
Total Proved	4,160	3,124	2,469
Probable	2,537	1,505	1,010
Total Proved Plus Probable	6,697	4,629	3,479

(1) Net present value of future net revenue does not represent fair market value of the reserves.

Sproule December 31, 2008 Forecast Prices

Year	WTI Cushing *US$/Bbl*	Edmonton Par Price *C$/Bbl*	Hardisty Heavy 12 API *C$/Bbl*	AECO C-Spot *C$/MMbtu*	Inflation Rate *%/Yr*	Exchange Rate *$US/$Cdn*
2009	53.73	65.35	47.05	6.82	2	0.80
2010	63.41	72.78	54.58	7.56	2	0.85
2011	69.53	79.95	59.96	7.84	2	0.85
2012	79.59	86.57	67.53	8.38	2	0.90
2013	92.01	94.97	74.08	9.20	2	0.95
2014	93.85	96.89	75.58	9.41	2	0.95
2015	95.72	98.85	77.10	9.62	2	0.95
2016	97.64	100.84	78.66	9.83	2	0.95
2017	99.59	102.88	80.25	10.05	2	0.95

Thereafter prices are escalated at various rates.

Finding Development and Acquisition Costs

	2008	2007	2006	3-Year Total
Capital Expenditures ($ millions)	**450.0**	394.1	133.1	977.2
Heavy oil/light oil and natural gas spending	**26%/74%**	27%/73%	54%/46%	30%/70%

	Proved				Proved Plus Probable			
($/boe)	2008	2007	2006	3-Year Weighted Average	2008	2007	2006	3-Year Weighted Average
Excluding future development costs:								
Finding and development costs	**14.26**	10.03	9.61	11.21	**10.53**	9.17	7.35	9.00
Acquisition costs (net of dispositions)	**22.99**	20.63	5.38	21.70	**15.83**	12.30	3.89	13.86
Finding, development and acquisition costs	**18.37**	14.75	9.57	15.01	**13.11**	10.90	7.31	11.02
Including future development costs:								
Finding and development costs	**11.01**	8.82	20.49	13.37	**12.09**	9.27	15.67	10.73
Acquisition costs (net of dispositions)	**27.87**	22.93	6.46	25.26	**20.23**	14.05	4.67	16.13
Finding, development and acquisition costs	**18.95**	15.10	20.36	17.67	**16.06**	11.91	15.66	12.98

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by Sproule. It does not take into account the possibility of Baytex being able to recognize additional reserves through future capital investment in its existing properties beyond those included in the 2008 year-end report.

Forecast Prices Before Tax

($ millions, except unit and per unit data)	Before Tax	After Tax
Net present value of proved plus probable reserves[1]	3,478.8	2,887.5
Value of undeveloped land[2]	199.2	199.2
Net debt[3]	(522.8)	(522.8)
Asset retirement obligations[4]	(49.4)	(36.7)
Net asset value	3,105,902	2,527,180
Total trust units outstanding[5] (millions)	98.4	98.4
Net asset value per trust unit ($)	31.57	25.69

Notes:

(1) Net present value of future net revenue discounted at 10% as evaluated by Sproule Associates Limited as at December 31, 2008. Net present value of future net revenue does not represent fair market value of the reserves.

(2) The value ascribed to the 797,130 net acres of undeveloped land Baytex held at December 31, 2008 was estimated by Management. This internal evaluation generally represents estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid during 2008 at Provincial Crown and State lands sales for the properties in the vicinity of our land holdings, less an allowance for near-term expiries. The 2008 acquisitions of land in North Dakota and Dodsland in Saskatchewan, which were made primarily in the second half of 2008, were valued at the amounts paid, less an allowance for near-term expiries.

(3) Long-term debt net of working capital as at December 31, 2008, excluding convertible debentures (which are assumed to be converted into trust units in the Net Asset Value calculation) and notional assets and liabilities associated with the mark-to-market value of derivative contracts (as the pricing effect of the derivatives contracts have already been reflected by Sproule in the values noted above).

(4) Management estimate of asset retirement obligations as at December 31, 2008 discounted at 8%.

(5) Includes 97,685,333 trust units, 705,763 trust units issuable on the conversion of the $10.4 million outstanding convertible debentures as at December 31, 2008.

ABBREVIATIONS

Abbreviations

AECO	the natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
bbl	barrel
bbl/d	barrel per day
Bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
Capex	capital expenditures
FD&A	finding, development and acquisition costs
F&D	finding and development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
LLB	Lloyd Light Blend
Mbbl	thousand barrels
*Mboe**	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
*MMboe**	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
RLI	reserve life index
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate

** BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Partner
Burnet, Duckworth & Palmer LLP

Edward Chwyl (2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan (1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Anthony W. Marino
President & Chief Executive Officer
Baytex Energy Ltd.

Gregory K. Melchin (1)
Independent Businessman

Dale O. Shwed (3)
President and CEO
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

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Fortis Capital (Canada) Ltd.
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

OFFICERS

Raymond T. Chan
Executive Chairman

Anthony W. Marino
President & Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Randal J. Best
Senior Vice President,
Corporate Development

Stephen Brownridge
Vice President, Heavy Oil

Brett J. McDonald
Vice President, Land

Timothy R. Morris
Vice President, US Business Development

R. Shaun Paterson
Vice President, Marketing

Mark F. Smith
Vice President,
Conventional Oil & Gas

Shannon M. Gangl
Corporate Secretary
Partner, Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

ANNUAL MEETING

Wednesday, May 20, 2009
3:00 p.m. (MST)
The Calgary Petroleum Club
319 – 5th Avenue S.W.
Calgary, Alberta, Canada

BAYTEX ENERGY TRUST

Suite 2200, Bow Valley Square II
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